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Retail Electric Competition in New York: Benefits for the Present, Promise for the Future

An Examination of Progress of Electric Market Restructuring in New York State, 1995-Present

May 1, 2007

Capitol Hill Research Center White Paper

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Study Concludes Retail Competition Has Applied Downward Pressure On Residential Prices in Texas' Competitive Retail Electric Market.

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Significant Rise in Price of Natural Gas and Other Factors Key Contributors to Increase in Retail Electric Prices Since 2002

Price of Generation Service Included in Overall Price of Residential Electric Service Has Decreased 13 Percent in Dallas and Houston Areas Since Competitive Market Began in 2002

AUSTIN, Texas -- Retail electric competition in Texas has applied downward pressure on the price of electricity for residential customers, according to a new study by Intelometry, Inc., entitled Texas Retail Electric Competition: Impact on Residential Prices 1995 - 2008. The study compares the price of generation service in the regulated rates of three electric utilities from 1995 to 2001 with the price of generation service in competitive residential prices offered by retail electric companies from 2002 through August 2008. In both regulated and competitive electric markets, the price of generation service is the primary component in the overall rate or price of retail electric service.

The study finds the primary price component decreased as much as 13 percent in the 2002-2008 period, following the inception of retail electric competition in Texas in 2002. For the three utility service areas analyzed, the study calculated the following price decreases:

* In the area served by CenterPoint, which encompasses Houston and surrounding areas, the price decreased by 13.87 percent;

* In Oncor's service area, which covers Dallas and other regions in North Texas, the price decreased 13.07 percent;

* In the area served by AEP Texas Central Company, which encompasses Corpus Christi and other parts of South Texas, the price decreased by 2.67 percent.

"Our goal was to achieve a fair and accurate comparison between what residential customers in Texas paid for electricity before and after competition began," said Jeff Merola, a vice president with Intelometry. "To compare regulated utility rates for residential service charged before 2002 and competitive prices available to residential customers in the market afterwards, we isolated the price of generation service in each of the two periods. We then adjusted the price component to account for three critical factors affecting retail electric prices that exist independent of retail competition: inflation, changes in the price of fuel used to generate power, and changes in the state-regulated charges for the delivery of power across transmission and distribution wires. The principal adjustment we made accounted for changes in the price of natural gas."

"Ultimately, we found retail electric competition to be good for Texas," added Merola.

Although the study shows retail electric competition in Texas has applied downward pressure on the price of electricity for residential customers, it also notes that the overall price of residential electric service has increased since the competitive market began in 2002. The study attributes this overall price increase to factors other than retail competition, notably the significant increase in the price of natural gas since 2002. The price of natural gas in August 2008 was more than three-and-a-half times the fuel's price in January 2002. According to the study, retail electric prices have increased as the price of natural gas has risen because natural gas is the predominant fuel source used to generate the electricity consumed in the state's competitive retail market.

Competition has also brought innovation to the Texas market, the study said. Consumers benefit from service and pricing options that did not exist before Texas moved to a competitive market in 2002.

"This study confirms what retail electric companies competing in Texas have said for some time - the competitive market works to the benefit of consumers in this state," said Steve Davis, president of the Alliance for Retail Markets. "The price benefit identified by the study is an important indication of the success of the Texas market."

Key observations of the study include:

1) Retail competition affects the price of generation service that is included in the overall price of retail electric service. The price for the delivery of electricity is also included in the overall price of retail electric service, but it is not affected by retail competition because the Public Utility Commission of Texas sets the level of the delivery price in regulated "wires charges."

2) Natural gas accounts for approximately 70 percent of the generation supply in the ERCOT region.

3) At its peak, the price of natural gas increased more than five-fold in comparison to the price in January 2002.

4) In October 2008, Dallas and Houston area residents could choose from more than 80 electricity products offered by approximately 25 different retail electric providers, including multiple 100-percent renewable energy options.

To download a full copy of the report, please visit: http://www.allianceforretailmarkets.com/studiesreports.html.

About The Alliance for Retail Markets

Founded in 2001, ARM is a member-driven advocacy organization of retail electric providers that advances the competitive retail electric market in Texas. Members include ConEd Solutions, Constellation NewEnergy, Direct Energy, Gexa Energy, Green Mountain Energy Company, Integrys Energy Services of Texas, Liberty Power, Sempra Energy Solutions LLC, Strategic Energy, Stream Energy, and SUEZ Energy Resources NA, Inc. For more information, visit: www.allianceforretailmarkets.com.

About Intelometry

Intelometry Inc. is a consulting services and software products provider specializing in the energy industry. Intelometry's experts advise government agencies, consumer advocacy groups, commercial & industrial businesses, financial institutions, and energy marketers on all facets of energy markets. Intelometry continuously monitors retail energy markets throughout the country and publishes the Retail Power Index[TM] (RPI[TM]), the only published index of its kind, which compares retail electricity prices in deregulated markets across the U.S. For more information, visit: www.intelometry.com.

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

ERCOT Texas's Competitive Power Experience: A View from the Outside Looking In

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Boston, Massachusetts
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ERCOT Texas's Competitive Power Experience: A View from the Outside Looking in

Executive Summary

Just under a decade ago, Texas started on a path to restructure its electric industry.[1] Fundamental changes in the state's electric industry have occurred since then. A little over a year ago, Texas completed the transition to a more competitive electric industry structure.

Taking a vantage point in mid 2008 and from outside of the state, this paper examines Texas's electricity market from two lenses: qualitatively, by looking at structural features; and quantitatively, by tracking performance using a range of numbers and metrics.

The first half of the paper describes whether Texas has structural attributes associated with a successful competitive market. These include the presence of: many buyers and many sellers; low barriers to entry (including prices over time that support new entry); non-discriminatory access of market participants to essential facilities necessary to participate in markets; means to mitigate the ability of market participants to exercise market power; informed consumers; transparency of prices and options; and relatively stable and transparent market rules.

Second, the paper also quantitatively evaluates results in the Texas electric industry in terms of the following parameters: reliability and infrastructure investment; the availability of suppliers and product offerings; price; environmental quality; and customer involvement. There are a variety of relevant and informative metrics that shed light on how well Texas's efforts to restructure its electric industry have satisfied the parameters necessary for an efficient competitive electricity market to develop and flourish. These retail and wholesale market metrics focus on: trends in real prices compared to input costs; diversity of retail products and suppliers; market share of incumbent companies; customers' options and choices, and awareness of them; retail consumer protections; entry of (and investment in) generation and transmission; entry of renewable resources; air emissions; and access to transmission.

Measured against all these metrics, Texas has had an overall successful competitive power market experience, having met the various qualitative and quantitative criteria for strong competitive market performance and conditions. How the Texas market has performed on these criteria is discussed below. However, Texas's success to date does not mean that improvements should not continue to be made. In particular, recent events demonstrate a need to improve ERCOT's management of congestion and the market design for the pricing of congestion. Also, technological advances on the customer side

[1] Throughout this paper, when using the term 'Texas,' I am referring primarily to the part of Texas controlled by ERCOT (the Electricity Reliability Council of Texas) – the largest and only region of Texas in which retail competition has been introduced. The reader should assume that I am referring to the ERCOT region of Texas unless the meaning is clearly all of Texas.

of the meter provide the Texas market a great opportunity to modify and reduce residential consumption (and household electricity bills) and the need for new power plants.

Texas's experience relative to various criteria for competitive electricity markets:

1. Retail customers have many options of electricity products from which to choose and offered by a wide array of providers. After a multi-year transition period, electricity customers in Texas's competitive markets are aware that they have options, can take advantage of easily-available information about products and prices, have many opportunities to choose electricity service options that fit their preferences, and are making choices in the retail market.

2. The focus of Texas's market has been on equipping consumers with information and options, and creating an environment in which consumers have the right as well as the responsibility to choose their electricity supplier without the intermediary of the wires company in between the supplier and the consumer. In parallel with development of an active retail market, there are strong customer protections in place, with continuing market oversight provided by state regulators.[2]

3. Texas emerged much more smoothly from its transition period to a fully competitive market than many other states in recent years. This resulted in part from policies that introduced consumers to the changing realities of prices in underlying energy markets as those changes unfolded over the past five years.

4. Significant investment in power plant and transmission infrastructure has taken place in Texas. Compared to other regions of the United States with restructured wholesale markets, ERCOT has experienced particularly strong capacity additions in the past decade. ERCOT's generating capacity additions are high in absolute terms (amounting to over 26,721 megawatts of new generating capacity from 1995 through April 2008). Also, taking into account the relative size of the market (in terms of peak demand levels[3]), ERCOT's cumulative capacity additions are relatively high.

5. Texas has excelled, in particular, in improving the air emissions from its power sector, and in developing its large wind resources for electric power production.

6. The grid has generally operated well, with reliable service delivered to consumers, although events in the spring/summer of 2008 point to a need to better manage and price transmission congestion.

In short, Texas's retail and wholesale markets show strong evidence of many of the basic features of competitive markets: the presence of many buyers and sellers; low barriers to

[2] Customer protection rules are periodically updated to adjust to market innovations and enhance customer protections.

[3] ERCOT had a peak demand of 62,188 megawatts (MW) in 2007, and an all-time record peak demand of 62,339 MW, which occurred August 17, 2006. ERCOT, "2007 Annual Report," June 12, 2008, p. 6, available at http://www.ercot.com/news/presentations/.

entry (including price levels that support (over time) new investment); non-discriminatory access of market participants to essential facilities (such as the wires) and other services necessary to participate in markets; rules in place requiring monitoring of market performance and mitigation of the ability of market participants to exercise market power; informed consumers; and transparent and relatively stable market rules.

Several factors have contributed to Texas's successful restructuring of its electric industry:

1. **Customer Focus**: Texas designed its power market with the customer as its focal point. Customers have been the target of information campaigns and efforts, of systems to ease switching and the provision of service, of relationships with competitive suppliers (rather than with the utility or the generator). Customer choice is considered both a right and a responsibility, in ways more akin to the expectations of customers in other types of markets than in traditional electric service arrangements provided by monopoly utility companies. In fact when commencing new service or changing service locations, customers must select a competitive provider. This selection process fosters the provider-customer relationship and enhances competition as retail electricity providers aggressively compete for new customers. Furthermore, similar to other types of markets, competitive retailers are allowed to manage their relationship with customers, including charging customer deposits and having the ability to issue disconnect orders for nonpayment for the utilities to carry out under guidelines of the Public Utility Commission of Texas.

2. **Design of Retail Default Service:** Texas designed its five-year transition in a way that assisted the state and its electricity customers in actually moving to full competition, rather than temporarily preventing customers from seeing price signals reflecting the realities of today's energy market conditions. The transition allowed for periodic price adjustments to its default price (the "Price to Beat," or "PTB") when underlying fuel and purchased power prices changed. Furthermore, in Texas the default provider is truly a competitive entity and not the incumbent utility. In fact the utility's only role is to provide the wires and poles service, and it cannot compete for customers. These facts allowed a robust retail electricity market to develop and served to *transition* consumers to a new industry model.

3. **Uniform Business Rules and Codes of Conduct:** Entry barriers for prospective retail electricity providers were lowered as a result of the policy to have uniform business rules and to centralize the electricity service registration functions at ERCOT. The 'Code of Conduct for Electric Utilities and Their Affiliates,' established in 1999, was important to ensure that competitive market participants (i.e., retail electricity providers and power generation companies) received non-discriminatory treatment by transmission/distribution utility companies. In addition, the Public Utility Commission of Texas has the authority to monitor market power associated with the generation, transmission, distribution, and sale of electricity in Texas and the responsibility to mitigate market power following a finding that market power abuses or other violations are occurring.

4. **Customer Education**: Aggressive customer education and outreach programs have supported a relatively informed base of retail electricity customers, with nearly universal awareness among "electricity decision makers" of their rights and responsibility to choose their supplier of electric service.

5. **Transmission Expansion Policies**: Texas supported generation investment through its transmission access and cost-allocation policies. In ERCOT's approach, new generation pays for only the direct costs of interconnecting with the transmission network, rather than for more remote transmission system enhancements needed to upgrade the network to accommodate moving power from the resource to demand centers.[4] These other costs are broadly socialized among all end-users. Such a policy has trade-offs, but served to broaden the geographic footprint of the markets, create incentives for generating capacity additions (including remote wind resources distant from loads) during the early years of the market, and provide customers access to remote generation resources. Texas's more recent efforts to identify and endorse Competitive Renewable Energy Zones ("CREZ") and support transmission plans to support them are a recent example of such policies.

6. **Initial Market Power Mitigation Policies**: Texas supported the start of the wholesale and retail markets through its initial policy of requiring affiliate power generation companies (by then separated from their traditional sister utilities) to sell entitlements to 15 percent of the power from its installed capacity in ERCOT. These auctions promoted competition by increasing the amount of generating capacity available to competitive retail electricity providers. Furthermore, a power generation company may not own and control more than 20 percent of installed generation capacity in ERCOT. A generation company that owns and controls more than this amount must take steps such as auctioning off entitlements to its generation capacity to reduce its share to 20 percent.

7. **Strong Policies for Environmental Improvement**: As part of its restructuring legislation, Texas ensured that emissions from electric generating sources would be reduced. Texas has policies that addressed air pollutants from fossil-fuel power plants, as well as development of wind and other renewable resources. Texas has also excelled in developing and constructing wind turbine capacity, not just because of the large wind resource in the state, but because the state's integrated market design, initial renewable energy mandate and transmission policies provided fertile ground for new wind generation.[5]

8. **Strong Alignment of Retail and Wholesale Market Design and Policies**: The Texas electricity wholesale and retail markets were designed at the onset as a unified whole to support the development of efficient markets in each. The state's initiatives enabled the market to develop many important "prerequisite" conditions for a market

[4] Ross Baldick and Hui Niu, "Lessons Learned: The Texas Experience," University of Texas at Austin, undated, p. 39.

[5] Texas does not have any siting or permitting requirements for wind generation. This paper takes no position on whether there should be any siting or permitting for wind generation.

to operate efficiently, including through structural changes; unbundling of the utilities into power generation, transmission/distribution and retail electricity providers; mandatory auctioning of incumbent utilities' entitlements to power for initial periods of the transition; grid operations and certain market-administration functions (e.g., energy balancing, ancillary services, switching registration functions) centrally carried out by ERCOT; market monitoring functions carried out under the oversight of state regulators, with the assistance of a third-party market monitor; establishment of a series of policies to support informed consumers; a bilateral contracting environment among willing buyers and willing sellers; and creation of an environment in which retail customers were the focus of core relationships in the competitive marketplace. Additionally, long-standing policies to support relatively short permitting periods and strong investment in transmission infrastructure facilitated the entry of generation and transmission capacity. Together, these allowed for the conditions necessary for an efficient electricity market.

9. **Stable Regulatory Environment**: Finally, a decade of relatively stable and transparent market rules has helped to send favorable signals to the investment community about prospects in the Texas market. These market rules include tools for the retail electric provider to manage bad debt risk, including the ability to disconnect for non-payment of electric service.

Generally, wholesale power markets currently face some barriers to entry as a result of the high cost of construction, continuing uncertainty over the timing and character of national carbon-control policy, and the topology of the transmission system. Texas's wholesale market is no exception. As the events of March-June 2008 demonstrated, it is important for the state to continue to make improvements in its particular wholesale markets. Examples of enhancements moving forward are continued efforts to: maintain an active and strong market monitor to ensure that market power is not exerted at the wholesale level; develop a vibrant demand response from consumers; determine the appropriate way to manage and price transmission congestion in the absence of a nodal market; proceed with plans for a nodal energy market which will provide improved price transparency and locational price signals; make continued improvements in transmission planning; and manage the impact of renewable generation (especially those with intermittent characteristics) on the grid.

On the customer side, technological advancements behind the meter, in combination with broad deployment of advanced metering systems and other demand-management technologies, will provide residential customers the information and ability to modify their consumption. Such changes should also bring distributed generation applications (such as solar) closer to commercial deployment. To make this a reality, ERCOT will need to charge customers based on their actual electric usage, rather than based on profiles. In combination with its competitive market, this advanced technology will position Texas well for future success.

Introduction

Just under a decade ago, Texas started on a path to restructure its electric industry. Since then, in the parts of Texas where the electric system is controlled by ERCOT, the state's electric industry has undergone fundamental change. The Texas legislature enacted a law overhauling the industry in 1999. Starting in 2002, large and small electricity customers, including residential customers, have had the ability to choose their electricity supplier, and incumbent affiliated generators were required to make power products related to a portion of their generating capacity available to the marketplace. In 2007, Texas completed its transition to a more competitive structure for its electric industry.

During this same period, many other states went through similar changes[6] – with less commitment to continue on a competitive path and less success.[7] Now that the transition period[8] has ended in Texas, the performance of its electricity markets is of interest to a wide variety of stakeholders: large and small consumers, policymakers inside and outside of Texas, power marketers and retailers, merchant generators, investors, and industry groups, among others. Texas's experience merits attention, because it has been a success even in light of external factors since 2002, including rising natural gas prices, the aftermath of the California energy crisis, the fallout from Enron's bankruptcy, and the changing views in some restructured states about the promise of competition in the electric industry.

From the vantage point of mid 2008, this paper examines the state of the restructured electric market in Texas, and evaluates how the market meets both various structural (qualitative) and quantitative criteria necessary for successful performance as a competitive market. The paper points out key market design criteria implemented and reasons underlying the successes in Texas. And it identifies aspects of the market design which warrant continued attention. This paper has attempted to look beyond the surface to explore what, if any, difference it has made that Texas's electric industry is somewhat unique compared to other regions of the U.S. Taking an admittedly outsider's point of view, the paper offers guidance for state policymakers as they consider ways to refine further the retail and wholesale electricity market structures to improve competition.

Assuming that the reader is relatively informed but not necessarily an insider with expert knowledge of the detailed, inner workings of Texas's (or any other) electric industry, the

[6] Examples of states that restructured their electric industries are Arizona, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, and Texas. All told, 14 states and the District of Columbia adopted restructuring laws, regulations or other policies and currently allow retail customers to choose their electricity provider. Energy Information Administration, "Status of Electricity Restructuring by State," April 2007, available at http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

[7] See, for example, the report assessing relative progress by states in implementing competitive retail markets: Nat Treadway (Distributed Energy Financial Group), "ARC's Baseline Assessment of Choice in the United States: An Assessment of Restructured Markets," Paper prepared for the Alliance for Retail Choice, May 30, 2007, available at http://www.allianceforretailchoice.com/ABACUSpublication.pdf.

[8] In Texas, the "transition period" took place during the first five years of competition where the affiliated retail electric provider had to make electricity available to residential and small commercial customers at the price to beat.

paper begins by describing what has happened in Texas and what type of "lens" is suitable for evaluating success and failure in a state's transition towards a competitive industry structure. The paper provides the results of our analysis of progress to date in Texas, based largely on up-to-date information in the public domain. Finally, the paper comments on what lessons might be learned by other states as they consider next steps in the development of their own electric industries in order to assure reliable, efficient and cleaner power supply for customers in their states.

The report is the result of an extensive literature review and data analysis drawn from a variety of sources.[9] The analysis is informed not only on information provided and interpreted by others, but also from the Analysis Group's research and the author's experience in energy industry, both as a former state and federal regulator and as an advisor to government organizations, consumer groups, energy companies, regional transmission organization, non-profit organizations, and others.[10]

[9] These sources include, for example, information provided by the Public Utility Commission of Texas ("PUCT"), ERCOT, industry data providers (public and private), various policy groups, industry trade associations, and industry and academic literature.

[10] The author, Susan F. Tierney, is a Managing Principal at Analysis Group in Boston. An expert on energy policy, regulation and economics, she has had a longtime focus on the electric and gas industries. A consultant for over a dozen years, she previously served as the Assistant Secretary for Policy at the U.S. Department of Energy (appointed by President Bill Clinton), the Secretary for Environmental Affairs in Massachusetts (appointed by Governor Weld), Commissioner at the Massachusetts Department of Public Utilities (appointed by Governor Dukakis), and executive director of the Massachusetts Energy Facilities Siting Council. She taught at the University of California at Irvine, and earned her Ph.D. and Masters degrees in regional planning at Cornell University. In addition to authoring many articles and reports, she has participated as an expert and advisor in regulatory proceedings before state and federal agencies and legislatures, in civil litigation cases, in arbitrations, negotiations, mediations, and in business consulting engagements, for clients in business, industry, government, non-profit and other organizations. She serves on a number of boards of directors and advisory committees, including the National Commission on Energy Policy. She is a director of Renegy Inc. (formerly Catalytica Energy Systems, Inc.); chair of the Board of the Energy Foundation; chair of the Board of Clean Air – Cool Planet (Climate Policy Center); a director of the Northeast States Clean Air Foundation; a member of the Advisory Council of the National Renewable Energy Laboratory, the Massachusetts Renewable Energy Trust Advisory Council, the Environmental Advisory Council of the New York Independent System Operator, and the WIRES' Blue Ribbon Commission on Cost-Allocation Issues for Transmission Investment. She chaired the Massachusetts Ocean Management Task Force, and authored the report on Liquefied Natural Gas to the Massachusetts Legislature's Special LNG Commission. Previously, she served as Director on the board of the Electric Power Research Institute (EPRI) and a member of the ISO-New England's Advisory Council.

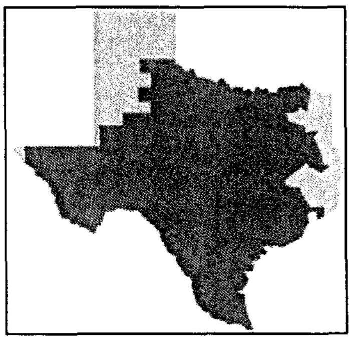
She was assisted in the preparation of this report by Andrea Okie, Katherine Franklin, and Laura Shiers of Analysis Group.

Texas's Electric Industry and its Competitive Structure: The Basics

The Electric Industry in the State of Texas

As Texas embarked on restructuring its electric industry, the industry had a traditional vertically integrated structure, with investor-owned electric utilities[11] providing service to most of the customers in the state under rates regulated by the Public Utility Commission of Texas ("PUCT"). The portion of the electric grid in the State of Texas that is under the administration of "ERCOT" (the Electric Reliability Council of Texas) was – and remains – essentially unconnected to electrical grids in other states and, in the absence of "electricity in interstate commerce," does not fall under federal regulation.[12] ERCOT is responsible for coordinating the reliable operation of the electric system in most of the state of Texas, representing 75 percent of its geographic area and about 85 percent of customer demand for power. (Figure 1 shows the ERCOT area as the dark blue portion of the state.)

Figure 1
Electric Reliability Council of Texas (ERCOT)[13] (shown in dark blue)



Texas has a diverse collection of power plants and transmission facilities in the state. In 1996, generating capacity for the ERCOT and non-ERCOT portions of Texas amounted to 73,360 MW, 88 percent of which was owned by utilities.[14] A decade later in 2006,

[11] At the time, the major utilities in Texas were: Central Power and Light Company ("CP&L"), El Paso Electric Company, Entergy/Gulf States Utilities Company, Houston Lighting & Power Company ("HL&P") which was part of Houston Industries ("HI"), Southwestern Electric Power Company ("SWEPCo"), Southwestern Public Service Company ("SPS"), Texas-New Mexico Power Company ("TNMP"), Texas Utilities Electric Company (also part of "TXU"), and West Texas Utilities ("WTU"). Today, several companies (CP&L, SWEPCo and WTU) are part of American Electric Power (although the retail part of the business for CP&L and WTU is now owned by Direct Energy); HI became Reliant Energy, whose two principal successor companies today are CenterPoint Energy and Reliant Energy (although the generation is now owned by NRG Energy); TXU is now known as TXU Energy, Luminant, and Oncor; TNMP is now owned by Public Service of New Mexico and SPS is now part of Xcel Energy.

[12] The Federal Energy Regulatory Commission ("FERC") regulates the terms and conditions of transmission and power sales in interstate commerce under the Federal Power Act.

[13] ERCOT, "Company Profile," May 15, 2008, available at http://www.ercot.com/about/profile/index.html.

[14] EIA, "State Electricity Profiles," February 1999, Table 4 (for Texas) available at http://tonto.eia.doe.gov/ftproot/electricity/stateprofiles/96st_profiles/statepro.pdf, p 266.

total generating capacity had increased to 100,754 MW, with only 25 percent owned by utilities and a significant amount of new renewable and gas-fired power plants added.[15] ERCOT had a projected reserve margin of 13.8 percent (with a 12.5 percent target) for 2008, and with a transmission system totaling 38,000 miles.[16]

The Design of the Texas Competitive Electricity Market

1999:	**Texas legislature enacts Electric Restructuring Act (SB7).**
2002:	**Texas Choice (retail competition) begins in ERCOT area; affiliate PGCs auction entitlements of 15% of their installed capacity until the earlier of 60 months or the affiliated REP lose 40% of its residential and small commercial load.**
2007:	**Transition period ends, ending "price to beat" ("PTB") rates to electricity customers offered by affiliated retail electricity providers ("REPs").**

After years of debate, the Texas Legislature enacted in 1999 the Texas Electric Restructuring Act (Senate Bill 7, or "SB7"), introducing competition into the Texas retail electricity market beginning on January 1, 2002. The law required Texas's vertically integrated investor-owned utilities to unbundle their business functions into three separate but possibly affiliated companies: a power generation company ("PGC"); a transmission and distribution utility ("TDU"); and a retail electric provider ("REP").

Since other new electric companies were also allowed to enter the market in Texas, the competitive subsidiary companies of the vertically integrated investor-owned utilities (or their successors) were called "affiliated" companies: affiliated PGCs and affiliated REPs. Each affiliated PGC had to sell, at auction, entitlements to at least 15 percent of its installed generation capacity, as long as that affiliated PGC owned 400 MW or more. This obligation would continue until the earlier of January 1, 2007, or the point at which 40 percent or more of the residential and small commercial customers in the TDU's service area were served by non-affiliated REPs.

Beginning January 1, 2002, all customers could leave their affiliated REP and buy power from another REP at a price mutually agreed-upon by the REP and the customer. Customers not choosing another REP continued to be served by the affiliated REP,[17] with "small"-use customers[18] paying the "Price to Beat" ("PTB") for electricity. Affiliated REPs' initial PTB rates were set at 6 percent less than the rates in effect on January 1, 1999, adjusted for changes in fuel prices. The PTB was allowed to be adjusted[19] twice

[15] EIA, "State Electricity Profiles," 2006, Tables 1 and 4 (for Texas) available at http://www.eia.doe.gov/cneaf/electricity/st_profiles/texas.html.

[16] ERCOT, "2007 Annual Report," May 2008, p 2.

[17] PUCT, "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2003, p. 41; Ross Baldick and Hui Niu, "Lessons Learned: The Texas Experience," University of Texas at Austin, undated, pp. 8-9.

[18] "Small" included residential and commercial customers with a peak demand of one megawatt or less.

[19] Adjustments occurred at the request of the affiliated REP and the approval of the PUCT. PUCT, "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2005, p. 52.

per year to reflect certain changes in fuel and purchased energy costs.[20] Affiliated REPs had to continue to charge the PTB rates to customers it served in its traditional service area through the earlier of January 1, 2005, or the date on which 40 percent of the power consumed by its residential or small commercial customers was supplied by other REPs. Thereafter, affiliated REPs could offer other rates but had to continue to make the PTB available for small customers until January 1, 2007. The transition period ended on January 1, 2007, at which point affiliated REPs were no longer required to offer service at the PTB.[21] There is a continuing restriction against any PGC owning/controlling more than 20 percent of the installed generation capacity deliverable to ERCOT.[22]

To help support retail competition, SB7 gave the PUCT new authorities, in addition to its traditional responsibilities to regulate utility companies. For example, the PUCT could: establish and enforce rules to protect retail customers from fraudulent, unfair, misleading, deceptive or anticompetitive practices; oversee all providers of electric service and assess administrative and civil penalties for violations; and carry out an extensive customer education program.

ERCOT took on new responsibilities as well. Beyond assuring system reliability, ERCOT's functions now include power scheduling, settlement, administration of a day-ahead ancillary services market,[23] and administration of the retail customer-switching functions. ERCOT serves as the registration agent for all retail transactions, including customer switch, move-in, and move-out requests. Monthly electricity

Highlights of SB7

- **Unbundling of vertically-integrated electric utilities into three separate businesses: generation; regulated transmission and distribution; and retail electric provider.**
- **Limitation (maximum of 20%) on ownership/control of generating capacity in ERCOT.**
- **Emissions reduction from older power plants.**
- **ERCOT (the ISO) has responsibility for coordinating the actions of market participants, ensuring system reliability, administering customer switching functions.**
- **Municipals and cooperatives are not affected by the law, unless they choose to open their territories to competition.**

Highlights of the Texas Choice Program

- **Retail competition started on January 1, 2002.**
- **Mandated 6% reduction from 1999 rates for residential and small commercial consumers (<1 MW), adjusted for changes in fuel prices. This was the "price-to-beat" and was the only price the affiliated REP could offer in its traditional service area to residential and small commercial customers until 2005 or until 40% of its load in a particular customer class was served by competitors.**
- **Companies were allowed to adjust their PTB rates twice a year in light of fluctuations in the price of natural gas and purchased power.**

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[20] The permissible adjustments related to changes in natural gas prices or in the market price of purchased power. PUCT, "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2003, p. 23.

[21] PUCT, "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2003, p. 22; PUCT, "Price-to-Beat," August 20, 2001, available at http://www.puc.state.tx.us/electric/train/files/pricetobeat.ppt; PUCT, "Substantive Rule. Chapter 25. Electric," October 25, 2001, available at http://www.puc.state.tx.us/rules/subrules/electric/25.41/ 21409pub.pdf, p. 10.

[22] This requirement covered generating capacity located in ERCOT as well as capacity deliverable into ERCOT. PUCT, "Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2007, p. 93.

[23] Market participants are assigned obligations for ancillary services based on their share of demand and can either self-provide these services or procure them through this ancillary services market.

usage data also flows through ERCOT.[24]

While Texas has a predominantly bilateral power market, there are short-term and other transactions which are carried out in the ERCOT-administered spot energy market (i.e., the balancing market). Qualified scheduling entitles[25] submit schedules of generation and load to ERCOT based on bilateral contracts and nominations to the balancing market. Market participants schedule transactions without relying on ERCOT to determine whether there is adequate transmission capacity available to accommodate the scheduled movement of power from the generation resource to the load. Under current rules, if all of the scheduled transactions cannot be accommodated because of transmission constraints, ERCOT avoids overloading lines and clears congestion using a zonal approach (e.g., clearing prices in balancing markets differ by zone when congestion arises). The costs associated with clearing the inter-zonal congestion are directly assigned to market participants, while intra-zonal congestion costs are charged to all retail providers on a load-ratio share basis.[26] The zonal approach is currently scheduled to change in 2009, when ERCOT moves to a nodal market design.[27]

ERCOT's administration of reliability, transmission, market oversight, retail customer-switching, and anticompetitive practices are regulated and overseen by state regulators at the PUCT.[28] The PUCT has created a new Market Oversight Division to address market

[24] PUCT, "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2003, p. 19.

[25] These Qualified Scheduling Entities ("QSEs") submit schedules on behalf of resource entities or load serving entities such as REPs, and are the primary entities that interface with ERCOT for scheduling power and participating in the energy market administered by ERCOT. QSEs must submit balanced daily schedules for their bilateral transactions with total generation and demand, specified at zonal level, and bid curves for zonal balancing up and balancing down energy. See PUCT, "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2005, p. 33 and ERCOT, "Qualified Scheduling Entities," available at http://www.ercot.com/services/rq/qse/index.html, accessed May 9, 2008.

[26] PUCT, "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2003, pp. 19, 49-50.

[27] In 2006, ERCOT decided to move from a zonal market system to a nodal system beginning in 2008. The grid will consist of more than 4,000 nodes, with central dispatch and locational marginal prices. ERCOT will operate a day-ahead market and a real-time market (replacing the balancing energy market). ERCOT, "Understanding: Texas Nodal Market Implementation," January 23, 2008, available at http://nodal.ercot.com/about/kd/understanding Nodal 012308. In May 2008, ERCOT announced that the nodal market would not open until early 2009, in light of software implementation issues, and the final revised implementation schedule is still in development as of this writing. ERCOT, "ERCOT Announces Delay in Nodal Market Launch Date," Press Release, May 20, 2008, available at http://www.ercot.com/news/ press_releases/2008/nr05-20-08; ERCOT, "Revised Nodal Schedule Pushed to October," Press Release, August 20, 2008, available at http://www.ercot.com/news/press_releases/2008/nr08-20-08.pdf.

[28] SB7 gave the PUCT authority to establish and enforce rules to protect retail customers from fraudulent, unfair, misleading, deceptive or anticompetitive practices, and to protect consumers' options to choose and their ability to be informed of their options. SB7 specifically provided that electricity customers would have: the right to safe, reliable and reasonably priced electricity, including protection against service disconnections in extreme weather emergency or in cases of medical emergency or for nonpayment of unrelated services; bills presented in a clear format and in language readily understandable by customers; information about rights and opportunities in the transition to a competitive electric industry; access to providers of energy efficiency services, on-site distributed generation and providers of energy generated by renewable energy resources; sufficient information to make an informed choice of service provider; protection from unfair, misleading or deceptive practices, including protection from being billed for services that were not authorized or provided; and an impartial and prompt resolution of disputes with retail electric providers and transmission and distribution utilities. SB7 §§ 39.101(a) and (b). Additionally, SB 7 authorized the

design flaws, identify and prevent market power abuses and encourage and facilitate competition in the bulk power, ancillary services and transmission services markets.

Measuring Success and Failure in Texas's Competitive Electric Market

Determining the "success" or "failure" of a restructured electric market is not easy. Inherent data limitations hinder the ability to draw perfect comparisons, either across regions or over time. Also, for obvious reasons, there are substantial limits on our ability to set up a "controlled experiment" or a "counterfactual" condition – something that a researcher might want to do to understand and draw contrasts with what Texas's electric market conditions would have looked like in the absence of the initiatives that began just under a decade ago.

Despite these limitations, one can look at traditional economic measures that are relevant for evaluating a competitive market's performance generally. From a structural point of view, this involves identifying whether key qualitative attributes of a successful competitive market are present: many buyers and many sellers; low barriers to entry (including prices over time that support new entry); non-discriminatory access of market participants to essential facilities necessary to participate in markets; means to mitigate the ability of market participants to exercise market power; informed consumers; transparency of prices and options; and relatively stable and transparent market rules.

This paper also evaluates success in Texas's electric industry by examining quantitative metrics relating to: reliability and infrastructure investment; the availability of suppliers and product offerings; price; environmental emissions; and customer involvement. There are many relevant and informative metrics that shed light on how well Texas's efforts to restructure its electric industry have satisfied the features allowing for an efficient electricity market to develop and flourish. These metrics focus on: trends in real prices compared to input costs; diversity of retail products and suppliers; incumbent market share; customers' options, choices, and awareness; retail customer protections; entry of (and investment in) generation and transmission; entry of renewable resources; air emissions; and access to transmission.

PUCT to oversee all providers of electric service and assess administrative and civil penalties for violations. SB7 §39.101(e), available at http://www.capitol.state.tx.us/tlodocs/76R/billtext/doc/SB00007F.doc.

<table>
<tr><th colspan="3">Measures of Success –
Texas's Electric Restructuring and Wholesale and Retail Power Market</th></tr>
<tr><th rowspan="2"></th><th colspan="2">Practical Metrics</th></tr>
<tr><th>Retail</th><th>Wholesale</th></tr>
<tr><td rowspan="2">Evidence in support of a successful competitive power market structure (retail, wholesale)</td><td>Competitive supply to retail customers with the option to choose their supplier (the "Texas Choice" program), with appropriate consumer protections. The overall package of policies was:
• Retail "price to beat" reflecting underlying trends in prices compared to input costs
• Diversity of retail product offerings
• Diversity of retail suppliers
• Customers choosing to be served by a competitive electricity supplier
• Ease of switching
• Customer awareness
• Customer protections
• Demand response</td><td>Adequate infrastructure resources
• Investment in generating capacity additions
• Investment in transmission
• Infrastructure for demand response and other demand-side reductions

Non-discriminatory access to transmission and other necessary facilities/services

Renewable resources and the environment
• Renewable resource capacity additions and energy output
• Reduction in SO_2, NOx
• Reduction in rate of CO_2 emissions

Efficient power production
• Adoption of an organized market (energy, ancillary services)
• ISO with responsibility for transmission, grid operations</td></tr>
<tr><td colspan="2">Regulatory oversight over:
• Retail customer safeguards
• Wholesale market design and performance
• Certification of retail suppliers
• Information provision</td></tr>
</table>

In the sections below, the performance of the Texas power market is examined using the qualitative and quantitative measures of success listed above and taking into account the constraints in data that inherently exist at present.

A Qualitative Analysis of the Texas Electricity Market Under Competition

Structural Features Important to a Successful Competitive Power Market

Standard economic theory dictates that a successful competitive electric market would display most, if not all, of the following attributes:

1. *Many Buyers and Sellers* – A successful competitive electric market will be characterized by the presence of many buyers and sellers at the wholesale and retail levels, so that no single market participant alone or acting in consort with others is able to exercise control over electricity prices and products offered in the market. Competition among sellers for customers is a key force in product innovation and efficient product pricing, removing the ability of sellers to earn profits set by market power rather than through the forces of competition. Competition among buyers (along with the ability of some customers to respond to changes in prices) is important for curbing their own ability to control prices and other terms of service.

2. *Low Barriers to Entry (including price levels that support (over time) entry of new investment)* – Establishing a market characterized by many buyers and sellers requires that there be low barriers to entry (i.e., buyers or sellers seeking to enter the market are able to do so without unduly complex, burdensome, time-consuming, or costly obstacles). (Conversely, high barriers to exiting the market also can distort competitive market conditions.) All else equal, the higher (or more difficult) the barriers to entry, the more costly it will be for a potential efficient competitor to compete with existing suppliers and the more likely it is that the latter may be able to exercise market power. In the long run, competitive markets should be expected to produce prices that yield revenues high enough to cover the costs of an efficient new competitor (or new investment from existing market participants) entering the market. Without prices over the long run producing such a signal for new investment, there will be inadequate incentives for efficient new entrants – contributing to likely shortages of supply, with attendant ability of incumbent suppliers to command prices above efficient levels for some period of time.

3. *Non-Discriminatory Access of Market Participants to Essential Facilities and Other Services Necessary to Participate in Markets* – Given the importance of transmission and distribution to link generators' supplies with customers' demands, a successful competitive electric market requires that participants be given non-discriminatory access to the "bottleneck" facilities needed to participate in the market. At the wholesale level, these critical elements include equal access to the delivery infrastructure (the "wires"), grid-operation/reliability services, and other market-administration functions. At the retail level where end-use customers are expected to enjoy options among suppliers of power, this non-discriminatory access includes fair and objective rules for switching, metering and billing, as well as a strong code of conduct that prevents affiliated

REPs from receiving cross subsidies, unfair access to customers, or a higher level of service or reliability from an affiliated TDU.

4. *Means to Mitigate the Ability of Market Participants to Exercise Market Power* – Market power is the ability of a single market participant to exercise control over prices for electricity or the type or number of electric products offered in the market. A participant with market power generally controls a large portion of the electric market, and as such, may be successful in raising electric prices without losing its customers to alternative market participants. In addition to other features (such as entry and exit conditions), competitive electric markets will be supported by structural and behavioral policies and controls in place to mitigate the potential exercise of market power.

5. *Informed Consumers* – A successful competitive electric market depends upon having customers aware of and informed about their choices in the new competitive market. Especially in light of the regulated monopoly conditions existing in the electric industry in most parts of the U.S. historically, having an informed consumer base is critical to the development of a competitive retail power market. Without knowledge that a market even *exists* where one did not exist in the past, consumers are unlikely to exercise their option to choose. Having informed customers increases the participation of many buyers in the marketplace.

6. *Transparency of Prices and Options* – At the retail level, customers must be able to easily identify and understand the electric products, prices, and options available to them. This includes providing customers with a clear means to compare different offerings.

7. *Relatively Stable and Transparent Market Rules* – Attracting new market participants to a competitive electricity market requires that relatively stable and transparent market rules exist. This is important not only to minimizing the cost to market participants – and in turn, to their ultimate customers – of conducting business in the market, but also of minimizing the barriers that potential new competitors face in entering the market. All else equal, stable and relatively transparent market rules thus reduce risk, foster economical operation, and support investment – all contributing to efficient competitive market conditions and price levels.

Sizing It Up: How Texas's Power Markets Fare, Compared to the Structural and Qualitative Attributes of Competitive Markets

Using the structural features listed above and taking into account elements of both wholesale and retail markets, Texas's power markets perform relatively well. Structural changes have enabled the Texas market to develop many important "prerequisite" conditions for a market to operate efficiently. Such structural changes include: unbundling of the utilities into generation, transmission and distribution companies;

divestiture of entitlements to power for initial periods of the transition; grid operations and certain market-administration functions (e.g., energy balancing, ancillary services, switching registration functions) carried out by the ERCOT as the independent system monitor; market monitoring functions carried out under the oversight of the PUCT and with the assistance of a third-party market monitor; establishment of a series of policies to support informed consumers; and a bilateral contracting environment among willing buyers and willing sellers.[29]

Based on information available in the public domain, the electricity market in Texas has many buyers and many sellers; relatively low barriers to entry; policies and practices to ensure non-discriminatory access to essential facilities; relatively effective means to address the potential exercise of market power; relatively informed consumers; relatively transparent prices; infrastructure investment levels indicating long-run prices supporting entry; and relatively stable and transparent market rules.

1. *Many Buyers and Sellers* – Unlike traditional regulated electric industries where retail customers have no choice but to buy electricity from the local utility, Texas's electric industry has many buyers and sellers of power in both the retail and wholesale portions of the industry. On the retail side, the Texas market attracted early and lasting interest among competitive retail electricity providers. Contrasted with pre-competition conditions where the incumbent utility was the only formal seller of power at retail, today there are many retail power sellers. As of August 2008, ERCOT's electricity markets had attracted hundreds of different individual market participants.[30] Texas's REPs have included affiliates of existing ERCOT utility

[29] According to the PUCT, a bilateral market enables REPs to have wide latitude to buy wholesale supply for long and short terms and in different packages to match the expected variances in its customers' demand for power over the next day, week, month, and year. Absent wholesale market power, this variety in contracting choices provides opportunities for REPs (as wholesale power supply buyers) to insulate themselves and their retail customers from price volatility in the power market. Initially, there were concerns among some stakeholders that in the bilateral market, affiliated REPs and their affiliated PGCs had largely contracted with each other, thereby limiting the ability of new generation plants to compete to serve retail customers. In 2003, the PUCT reported its view that this situation would decrease over time as the ties between the affiliated REP and PGC diminished as customers switched to alternate suppliers and increased pressures were placed on the affiliated REPs to procure the least expensive power available. The PUCT also adopted a rule that requires power generators, power marketers, and others who sell power at wholesale in Texas to file quarterly reports concerning their wholesale power transactions in the state. Wholesale market participants need to provide information regarding their bilateral contracts, including price information, to the PUCT, which then discloses the data while protecting the confidentiality of individual buyers and seller. PUCT, "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2003, pp. 77, 126; and PUCT, "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2005, pp. 18, 45.

[30] ERCOT's listing of market participants as of August 20, 2008, included: 122 certified competitive retailers, 138 unique qualified scheduling entities, 277 load-serving entities, 231 resource entities; and 150 transmission/distribution service entities including municipals and cooperatives. ERCOT's listing of all market participants does not track power marketers and does not distinguish the active or inactive status of an entity in the market. A single market participant may be operating within multiple TDSPs or under separate company names. ERCOT, "List of Certified Competitive Retailers," http://www.ercot.com/mktparticipants/docs/UpdatedCertifiedCRs%2008192008.xls, updated as of August 19, 2008; ERCOT, "List of Qualifying Scheduling Entities," http://www.ercot.com/mktparticipants/docs/QSEs.xls, updated as of July 23, 2008; ERCOT, "List of Market Participants in ERCOT Region," http://www.ercot.com/mktparticipants/docs/List%20of%20all%20Market%20Participants_0808.xls, updated as of August 8, 2008; as of August 1, 2008, there were 185 registered (active) power marketers in Texas. PUCT, "Market Directories & Utilities: Electric Companies Serving Texas," available at http://www.puc.state.tx.us/electric/directories/pm/pm_list.htm.

companies selling outside of their home territories, affiliates of out-of-state utility holding companies, and many other well-established and newly formed independent energy producers.[31] And the number of distinct ("unique"[32]) REPs (competitive and affiliated) serving residential customers in Texas held steady between 2002 and the start of 2005, with 10 to 12 unique REPS, but more than doubled from 11 at the start of 2005 to 27 at the end of 2007.[33]

2. *Low Barriers to Entry (including price levels that support (over time) entry of new investment)* – The success of Texas in attracting wholesale and retail suppliers to enter the market is indicative of the presence of low barriers to entry. A core feature of Texas's retail market design – i.e., the transition process that permitted adjustments in the price to beat to reflect changes in underlying market costs – gave competitive REPs the ability to enter the market with a fighting chance to compete. This contrasts with the experience of other restructured states which discounted and/or froze retail transition prices over many years, a situation that caused market prices to diverge significantly over time from the default service rate; the chronically below-market "default service" price inhibited entry of new market participants who had no choice but to sell at market prices. Also on the retail side of the market, entry barriers for prospective REPs were lowered as a result of Texas's uniform business rules[34] and the centralizing of electricity service registration functions at ERCOT.[35] On the wholesale side of the market, ERCOT experienced 26,721 megawatts ("MW") of generating capacity additions from 1995 through April 2008, with another 6,438 MW of capacity under construction as of April 2008.[36] For a regional power market with a peak load over 62,000 MW,[37] this is strong evidence of relatively low overall barriers to entry in generation markets. This reflects not only the expectation of long-term price levels supporting new investment, but also a variety of other features in the

[31] Robert J. Michaels, "Competition in Texas Electric Markets: What Texas Did Right & What's Left to Do," Texas Public Policy Foundation, March 2007, p. 11.

[32] This refers to the fact that REPs may end up selling different types of products in the territories of more than one provider of distribution service. The "unique" number of REPs avoids double counting of these separate offerings by individual companies.

[33] See Figure 12 and corresponding text below for a complete discussion.

[34] The PUCT's "Code of Conduct for Electric Utilities and Their Affiliates," established in 1999, was important to ensure that REPs and PGCs were treated equally by transmission distribution companies. The code's stated purpose was to "establish safeguards to govern the interactions between utilities and their affiliates, both during the transition to and after the introduction of competition, to avoid potential market-power abuses and cross-subsidization between regulated and unregulated activities." PUCT, Substantive Rule § 25.272, available at http://www.puc.state.tx.us/rules/subrules/electric/25.272/25.272.pdf.

[35] See further discussion below.

[36] Data are through April 2008. Of the amount of new generation added, 25,894 MW are natural gas power plants; 200 MW of nuclear; 388 MW of wind; 147 MW of coal; and 92 MW of other power production capacity. Also as of April 2008, there was 6,438 MW of additional capacity under construction: 1,644 MW of natural gas fired generation; 470 MW of wind; 3,966 MW of coal fired generation. In addition, there was 25,497 MW of announced capacity as of April 2008: 11,463 MW of natural gas; 9,002 MW of nuclear; 470 MW of wind; 3,318 MW of coal; and 1,244 MW of other power production capacity. Based on an analysis of ERCOT Operations and Systems Planning Data (as of October 2007) as reported by the PUCT (in November 2007), and as updated by Energy Velocity Database (as of April 2008).

[37] As of this writing, ERCOT's all-time record peak of 62,339 MW occurred on August 17, 2006. ERCOT, "News Bulletin," August 21, 2007, available at http://www.ercot.com/news/press_releases/2007/nr08-21-07.html.

Texas market including relatively expeditious power plant permitting processes, market-based access to generating supply resources at the outset of the markets, and favorable transmission access policies (see below). Looking ahead, the current high costs to construct and finance electric and other infrastructure,[38] along with the continuing uncertainty relating to the timing and character of U.S. carbon control policies in the years ahead, now create barriers to entry to new coal generation – although these factors are not unique to Texas and do not appear yet to have had a measurable impact in the state.

3. *Non-Discriminatory Access of Market Participants to Essential Facilities and Other Services Necessary to Participate in Markets* – Texas's wholesale market was designed in conjunction with its retail market, with an array of policies put in place to ensure that market participants would have access to systems and facilities needed to participate in the market. Three aspects of the market design – tied to unbundling and divestiture, transmission access and cost-allocation, and market administration – are notable in this regard. First, existing generating capacity was made available to retail electricity providers in the early years of the market. Prior to the opening of Texas Choice, incumbent generation owners were required to sell at auction multi-year entitlements to at least 15 percent of the power from their generation capacity. These auctions promoted competition by increasing the amount of generating capacity available to competitive and affiliated REPs alike.[39] In parallel, growing demand for electricity in Texas and the entry of new REPs needing supplies opened up markets for developers/owners of new generating capacity as well. Second, new generation facilities in Texas pay only for direct costs to interconnect to the transmission system, rather than also paying for "deep" inter-connection costs for any upgrades to the network needed to accommodate moving power from the resource to demand centers.[40] Third, Texas adopted a centralized system for_administering the customer "move-in" and "switching" processes needed whenever a retail customer initiated service with a REP or changed service from one REP to another. ERCOT, as the centralized registration agent for the competitive retail market in Texas, has responsibility to receive and manage the transaction orders to assure that customers receive electric service when they move to a new location (or move out of one), start up electric service, arrange for power to be supplied by a REP, and track monthly electricity usage data. This centralized "service registration" function (at ERCOT) in Texas is different than in other states where these functions are carried out by the local distribution utility, which can cause the retail electricity provider to build multiple registration systems for a single state. In Texas, the goal had been to develop a relatively smooth process not only for consumers but also for REPs seeking

[38] Susan F. Tierney, "Decoding Developments in Today's Electricity Industry - 10 Points in the Prism," paper prepared for the Electric Power Supply Association, October 2007, pp. 4, 6.

[39] Affiliates of the incumbent generation company (including affiliated REPs) were prohibited from purchasing the capacity entitlements.

[40] In some other jurisdictions, developers of new generation projects pay upfront for local and system upgrades to the transmission network necessary to deliver their energy to demand. Other costs are broadly socialized among all users. Ross Baldick and Hui Niu, "Lessons Learned: The Texas Experience," University of Texas at Austin, undated, p. 39.

to participate in the Texas market, especially in service areas that would otherwise be small markets.[41] Fourth, competitive REPs in Texas operate in a manner similar to more traditional competitive industries, and differ in key ways from policies and practices in some other states with retail choice. For example, customers initiating service in Texas must select a competitive provider, unlike in other restructured states where a new customer must initiate service in the first instance with a utility and then separately switch to a competitive provider. Texas also has strong codes of conduct and prohibitions on the utility being in the merchant function. Finally, competitive REPs in Texas are allowed to manage directly their credit and collection relationship with customers in a manner similar to more traditional competitive industries; in most other states, these relationships between competitive suppliers and their retail customers must occur with the utility as a middle man. In Texas, competitive REPs can charge deposits and issue disconnect orders to the utilities to implement for non-payment in accordance with PUCT rules. Also, certain social policies regarding low-income customers are addressed in a competitively neutral manner, as described later in this paper.

4. *Means to Mitigate the Ability of Market Participants to Exercise Market Power* – Texas restricted the ability of individual market participants to exercise market power through several methods. SB7 mitigated wholesale market power by limiting a power generation company from owning or controlling more than 20 percent of the installed generation located in, or capable of delivering power into, ERCOT. The initial 15-percent capacity entitlement auctions allowed non-affiliated[42] REPs an opportunity to gain access to power from existing generation capacity. The mandate for vertically integrated investor-owned utilities to unbundle into three separate companies – a PGC, a TDU, and a REP – allowed all REPs and PGCs equal access to service from TDUs. Non-discriminatory access to the grid was further supported through ERCOT's role as the independent grid administrator. Finally, Texas established market monitoring and mitigation functions, which are carried out under the oversight of the PUCT with the assistance of a third-party market monitor.[43]

5. *Informed Consumers* – From even before the opening of its retail market in 2002, Texas adopted a strong consumer education effort. SB7 (1999) established and the PUCT administered – and still operates – an extensive customer education campaign in areas open to retail competition to inform retail customers about their choices in the new retail competitive electricity market. While there is a broad-based effort targeted to all consumers, there are also forms of assistance targeted to low-income and non-English-speaking electricity users. The "Texas Electric Choice" campaign

[41] PUCT, "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2003, pp. 19, 51.

[42] In Texas, the incumbent REP was not considered to be an affiliated REP in TDU areas outside its incumbent territory.

[43] PURA 39.157 provides the PUCT the authority to monitor market power associated with the generation, transmission, distribution, and sale of electricity in Texas and the ability to require mitigation of market power following a finding that market power abuses or other violations are occurring. PUCT, "Public Utility Regulatory Act" (PURA), September 1, 2007, available at http://www.puc.state.tx.us/rules/statutes/Pura07.pdf.

uses four primary methods to educate Texans about the changes in the electric industry. These are: outreach and public service announcements;[44] a call center to handle questions and answers;[45] educational literature, including brochures, fact sheets and other materials sent via e-mail or distributed; and a "Power to Choose" website to enable customers to compare product offerings across different REPs, and to search for and identify product offerings by various criteria.[46] These various forms of customer education and assistance have been designed to give customers the information they need to understand the new competitive market and to assist them in understanding their options. While the PUCT's services provide assistance, the aim in the end has been to prepare consumers to interact directly with competitive electricity providers in a normal commercial relationship.[47] Indeed, REPs also provide educational material and informational services to consumers. In part as a result of these educational efforts, there is strong indication that in Texas, consumers are aware of the fact that they are in a state with a restructured electric industry. In ERCOT Texas, awareness of "retail choice" is almost universal among individuals responsible for making decisions about their electricity supply: according to consumer polls at the end of 2006, 92.5 percent of electricity "decision-makers" in deregulated areas were aware that they could choose their electric company.[48]

6. *Transparency of Prices and Options* – In Texas's retail power market, price transparency is high. Retail customers have many ways to identify and compare the variety of available electric product offerings. The PUCT's "Power to Choose" website provides consumers with the ability to directly compare product offerings between different REPs, and search for and identify product offerings by various criteria. During the fourth and fifth years of the campaign website there were more than 700,000 unique visitors to the website and more than 13 million total page views. The excerpt shown in Figure 2 below from PowerToChoose.org shows a small portion of the many offers a consumer in one area could compare and contrast, with high price transparency.

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[44] "Outreach and Public Service Announcements" include radio announcements, a network of organizations that distribute literature (reaching 312,440 people during 2006), television outreach events (with 2 million viewers in June 2006), and public-service-announcement program (reaching an audience of almost 3 million in the restructured service areas). These public service announcements allow information to be aired at one-fifth the cost of commercial airtime. The call-in center has a staff in place six days a week, with an automated system with answers available on all days of a week. PUCT, "Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2007, pp. 45-46.

[45] A toll-free bilingual answer center is available to consumers as a way to obtain answers to their questions. PUCT, "Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2007, p. 46.

[46] PUCT's "Power to Choose" website (www.PowerToChoose.org and the Spanish version, www.PoderDe Escoger.org) and PUCT, "Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2007, pp. 45-46.

[47] Power to Choose Website, "Compare Offers Now," May 14, 2008, available at http://www.powertochoose.org/ _content/_compare/compare.aspx. PUCT, "Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2007, pp. 45-46.

[48] This poll focused on those individuals responsible for making decisions about their electricity providers (e.g., the person who pays the electricity bill). The 92.5 percent awareness as of December 2006 was up from 84.1 percent in December 2004, and from 66.8 percent in August 2002 "Texas Directions Poll," Conducted by the Ampersand Agency on behalf of Sherry Matthews Advocacy Marketing, January 2007.

Figure 2

Retail Electric Provider	Avg. Price/kWh (1,000 kWh)	Cost per 1,000 kWh	Rate Type	Renewable Energy Content	Term (Mo.) Cancellation Fee
YEP *Guaranteed Savings & No Long Term Commitment E-Plan* Terms of Service | Facts Label Sign Up | Special Terms	14.8¢	$148.00	Variable	0%	1 Variable
Cirro Energy *Smart Pass 12* Terms of Service | Facts Label Sign Up | Special Terms	14.6¢	$146.00	Variable	2%	12 One month's average usage
Gexa Energy *Gexa Green 6* Terms of Service | Facts Label Sign Up | Special Terms	13.8¢	$138.00	Fixed	100%	6 $150.00
Amigo Energy *Online 12-month Commitment Program* Terms of Service | Facts Label Sign Up | Special Terms	14.1¢	$141.00	Fixed	0%	12 $69.95

Source: Power to Choose Website, "Compare Offers Now," October 20, 2008, available at http://www.powertochoose.org/_content/_compare/compare.aspx.

Third-party information providers have also emerged in Texas. For example, a number of on-line energy marketing firms have emerged in the past few years to assist customers in shopping among the services of competitive suppliers. These sites list rates and different plan types for residential and commercial customers, make recommendations about various suppliers based on the particular selection criteria identified by customers, and provide links to competitive REPs' own websites for registration and sign-up.[49] Akin to the on-line marketing services that have developed in other industries (e.g., hotels, airline fares), these third-party marketing agents assist REPs and facilitate comparison shopping by consumers, sometimes even

[49] See, for example, http://www.saveonenergy.com; http://www.chooseenergy.com; http://www.electricitytexas.com/; http://www.texaselectricrate.com/; http://www.texaselectricservice.com/; http://www.electricitybid.com/texas-electric-company.html, and http://www.whitefence.com. See also, Restructuring Today, "SaveOnEnergy's New Shopping Website Debuts in Texas," September 5, 2007.

offering inducements (like gift cards or other perks) for choosing to buy electricity from a particular competitive REP.[50]

7. *Relatively Stable and Transparent Market Rules* – In Texas, a decade of relatively stable and transparent market rules has helped to send favorable signals to the investment community about prospects in the Texas market. While other states have begun to analyze whether to continue to pursue a competitive approach, Texas regulators have maintained support for the competitive structure in place in ERCOT Texas, with recent regulatory actions aimed at assuring improvements in the market's performance.[51]

A Quantitative Analysis of the Texas Electricity Market Under Competition

Reliability and Infrastructure Investment:

What Has Happened in Texas?

Assuring reliable electric service to customers involves a number of elements, some of which relate to the adequacy of the physical infrastructure of power plants, transmission lines, local distribution lines, and some of which relate to operations and maintenance practices related to this physical infrastructure, with others tied more to the overall character of the operators of the grid.

An important metric for evaluating the success of Texas's system, therefore, is whether there is "enough" or "adequate" amounts of infrastructure – generating stations, transmission lines, demand-side response technology and resources – to assure that the system can operate reliably, consistent with the standards adopted in the electric industry to avoid unacceptably high levels of outages caused by inadequate infrastructure. Several metrics are useful for analyzing resource adequacy – investment in generating capacity,

[50] Restructuring Today, "Energy Shoppers Get Big Rewards at SaveOnEnergy.com," July 24, 2007; "SaveOnEnergy.com's Retail Exchange Portal Offers Texas Companies a Convenient Way to Shop for Lower Electric Rates; Fast and Simple Process Well-Received by Texas Businesses," *PR Newswire*, February 19, 2008.

[51] See, for example, Potomac Economics (ERCOT Independent Market Monitor), "2006 State of the Market Report for the ERCOT Wholesale Electricity Markets," August 2007, generally and p. xxxi. Recent statements from current PUCT commissioners indicate their support for the way that Texas has met the challenges in the electric industry, including through stable policies and implementation of SB7. See, for example, Barry T. Smitherman, Chairman, PUCT, "Theory is Clean; Life is Messy – Continuing Developments in the ERCOT Market," Remarks to the Gulf Coast Power Association Fall 2007 Conference, October 3 and 4, 2007, available at http://www.puc.state.tx.us /about/commissioners/smitherman/present/pp/GCPA_100307.pdf; Julie Caruthers Parsley, Commissioner, PUCT, "What Have You Done For Me Lately? A Look at the Texas Competitive Electricity Market," April 2008, available at http://www.puc.state.tx.us/about/commissioners/parsley/present/epp/CompetitiveElectricMarketUpdate-Apr2008.pdf; Paul Hudson, [then] Chairman, PUCT, "State of the Electric Market," Remarks to the Senate Business & Commerce Committee, February 20th, 2007, available at http://www.puc.state.tx.us/about/commissioners/hudson/present/pp/ SBC_022007.pdf; Paul Hudson, [then] Chairman, PUCT, Remarks to the Gulf Coast Power Association, October 4, 2006, available at http://www.puc.state.tx.us/about/ commissioners/hudson/present/pp/GCPA_100406.pdf.

capacity or reserve margins, investment in transmission system additions, and investment in infrastructure needed to provide demand response.

Investment in New Generation: Texas has experienced substantial investment in clean, new generation under restructuring. Because the generation market is restructured, the actual amount of total dollars invested in generating resources is not publicly available. The PUCT has estimated the investment at approximately $20 billion, for new generation added in the past decade.[52] Changes in capacity additions in the past decade, however, indicate a high level of investment interest in the state's power market. Between January 1996 and April 2008, ERCOT added 26,721 MW of new capacity.[53] With this new generating capacity, and netting out 9,548 MW of retired and mothballed capacity, ERCOT has a wholesale market with 72,820 MW of generating capacity within ERCOT to meet the 62,339 megawatts system peak demand in ERCOT.[54]

Figures 3 and 4 further indicate investors' interest in entering the ERCOT Texas market over the period in which restructuring has taken place. Prior to the post-2000 rise in natural gas prices, most of the new power plant additions were gas-fired power plants. More recently, a mix of types of capacity (including coal, nuclear, natural gas and wind) has been newly proposed each year and is still reported as being in development.[55] In particular, since the start of 2002, significant wind resources have been added – total *summer installed* capacity of 1,990 MW between 2002 and 2006, with another 1,489 added in 2007 alone.[56] Development interest in wind generation shows strong interest (with 1,229 MW of new development announced as of the end of 2007) (see Figure 4).

Compared to other regions of the United States with restructured wholesale markets, ERCOT has particularly strong capacity additions in the past decade. Figure 5 compares

[52] Julie Caruthers Parsley, Commissioner, PUCT, "What Have You Done For Me Lately? A Look at the Texas Competitive Electricity Market," April 2008, p. 16, available at http://www.puc.state.tx.us/about/commissioners/parsley/present/epp/CompetitiveElectricMarketUpdate-Apr2008.pdf. This $20 billion estimate is roughly consistent with an approach I used previously in another white paper, to calculate the dollar level of investment in new generation capacity in recent years in the U.S. Susan F. Tierney, "Decoding Developments in Today's Electricity Industry - 10 Points in the Prism," paper prepared for the Electric Power Supply Association, October 2007, footnote 10, in which I assumed a capital cost of approximately $550/kW for combined cycle natural gas power plants based on RDI's Outlook for Power in North America 1999, Annual Addition (2000). (More recent estimates of capacity costs are much higher.)

[53] Based on an analysis of ERCOT Operations and Systems Planning Data (as of October 2007), as reported by the PUCT (in November, 2007), and as updated by Energy Velocity Database (as of April 2008).

[54] All time peak in August 2006. ERCOT, "2007 Annual Report," May 2008, p. 2.

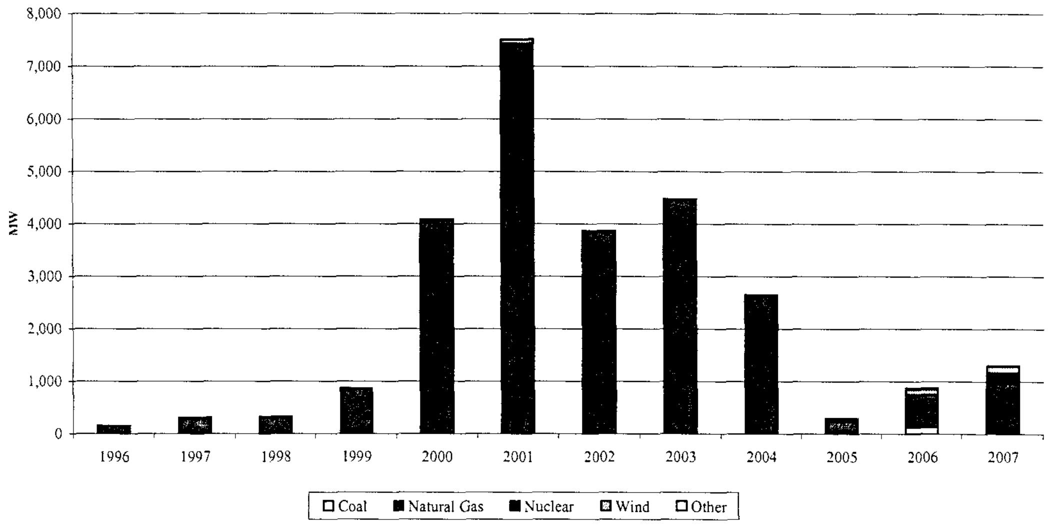
[55] Figure 4 shows the year in which each new project was announced, for projects that were still active in January 2008. Announced projects that were cancelled prior to January 2008 have been excluded as have projects in early stages of development whose status has not been publicly disclosed, where voluntary.

[56] Note that the capacity shown in Figure 3 suggests a lower amount of wind capacity has been added in ERCOT than is indicated in this sentence, which reports summer installed capacity value of wind turbines. The capacity amounts in Figure 3 (and in subsequent Figure 6, later in this report), reflect the *capacity value* of generating units as counted by ERCOT for resource adequacy analyses (i.e., reserve margin planning purposes). For those purposes, ERCOT discounts the capacity of wind units to 8.7 percent of nameplate capacity value, to reflect the amount that can be relied upon in the peak hour for capability planning purposes. The nameplate values are relevant here for indicating the significant amount of development of wind resources, which are capable of providing power in other periods besides the peak hour.

cumulative power plant capacity additions in ERCOT with those in California (the "CAISO," or California ISO region), New York (the "NYISO" region), New England (the "ISO-NE" region), and the PJM region (in the Mid-Atlantic and portions of the Midwest area). As shown, ERCOT's generating capacity additions are high in absolute terms, but also in terms of its relationship to its 2007 summer peak demand. Taking into account the relative size of the market (in terms of peak demand levels), ERCOT's cumulative capacity additions are higher than in the other regions (except New England).

Figure 3

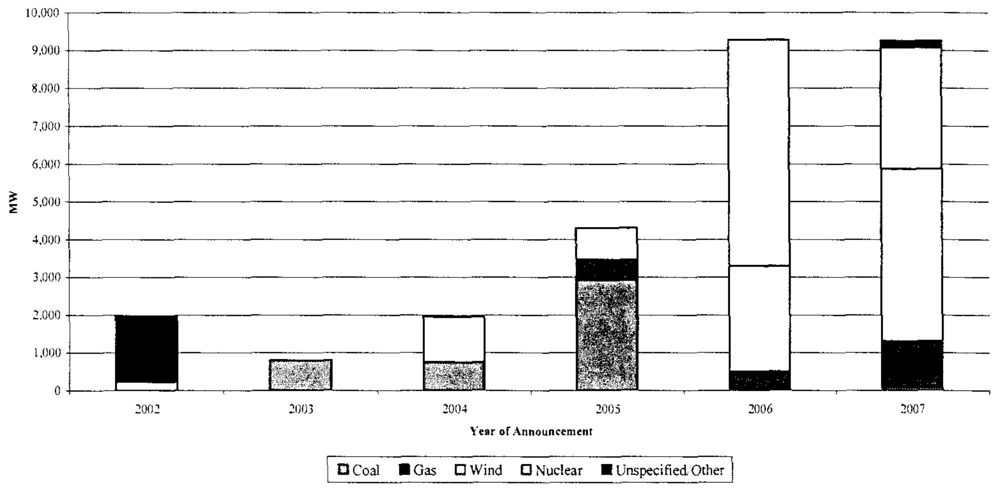
ERCOT Summer Capacity of Plants Added by Fuel Type (MW) January 1996 - November 2007



Notes:
1. Wind generation is discounted to 8.7% of summer capacity to reflect ERCOT's treatment of wind generation in its reserve margin analysis.
2. Capacity resources do not include DC Ties.
Source: Analysis of ERCOT Operations and Systems Planning Data as reported by the PUCT and Energy Velocity Database and ERCOT, "Report on the Capacity, Demand, and Reserves in the ERCOT Region," May 2008.

Figure 4

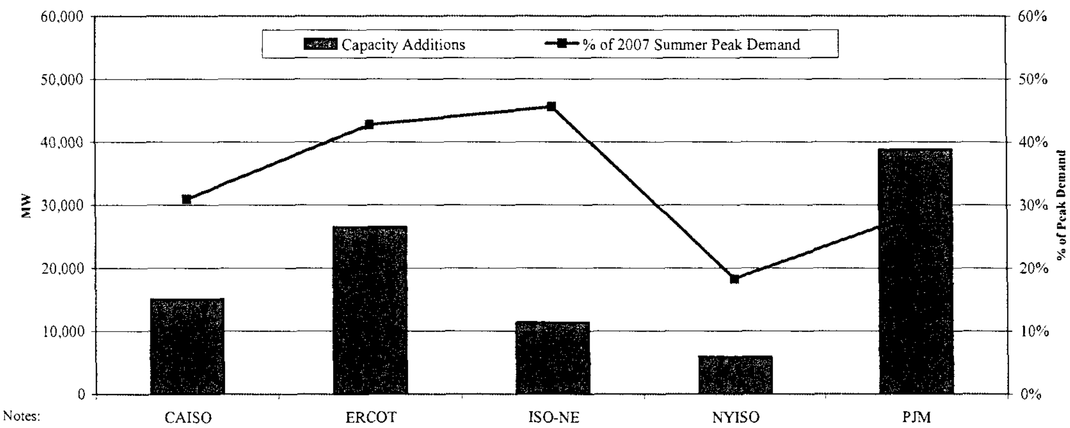
ERCOT Capacity of Plants Currently Under Development
by Fuel Type (MW) and Year of Announcement
July 2002 - December 2007



Notes:
1. Data for new plants under development are based on "Date of Application for Interconnection."
2. Proposed projects have signed an application for interconnection.
3. "Unspecified/Other" includes combined cycle and combustion turbine.
4. Data do not include plants that were cancelled or projects under early stages of development.
Source: ERCOT Operations and System Planning Data, available at http://oldercot.ercot.com/tmaps/ListMaps.cfm?GroupID=50, as of January 22, 2008.

Figure 5

Capacity Additions by ISO Region (MW and % of 2007 Summer Peak Demand)
1997 - 2007



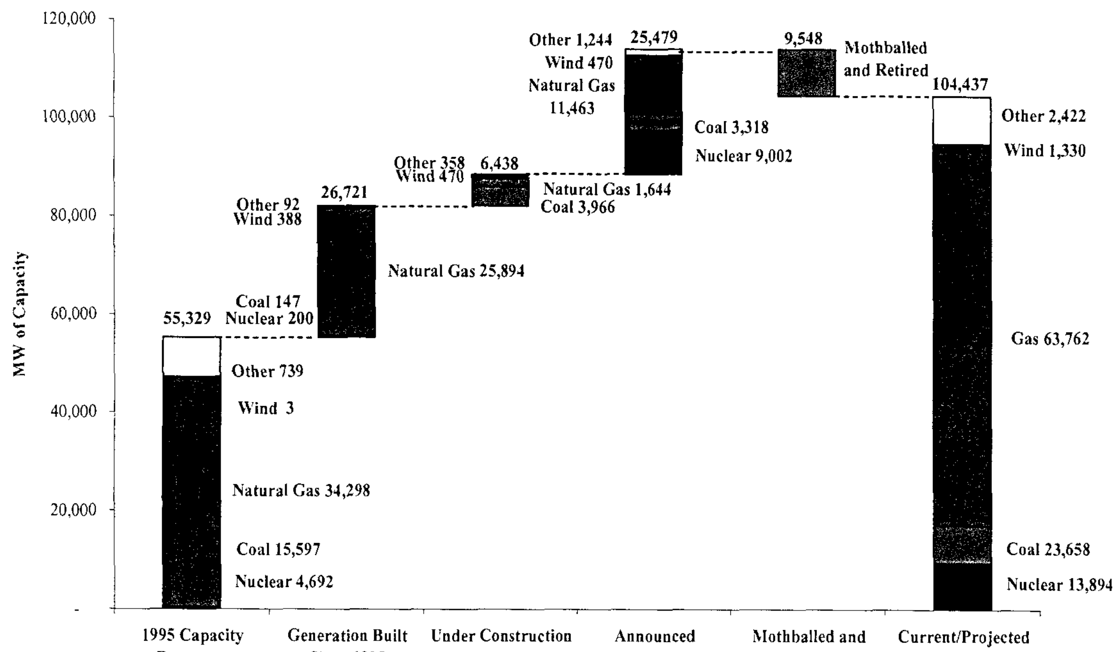
Notes:
1. The NYISO 2007 summer peak demand data is a forecasted value before reductions for Emergency Demand and Response Programs.
2. The actual 2007 summer peak demand was 48,615 MW in CAISO, 62,188 MW in ERCOT, 25,773 MW in ISO-NE, 139,428 MW in PJM, and forecasted as 33,447 MW in NYISO.
3. Capacity additions only include capacity from plants that are currently operating and exclude capacity from plants that are currently retired or mothballed. Data for ERCOT come from ERCOT Operations and Systems Planning Data, the PUCT and the Energy Velocity Database. The data for the remaining ISOs come from Platts BaseCase.

Sources:
1. California ISO, "California ISO Peak Load History 2007," April 25, 2008.
2. ERCOT, "Report on Existing and Potential Electric System Constraints and Needs," December 2007.
3. ISO New England Annual System Peak, Day & Hour Workbook, May 13, 2008.
4. New York ISO, "2007 Load and Capacity Data," April 1, 2007.
5. PJM, "2007 State of the Market Report," March 11, 2008.
6. Analysis of ERCOT Operations and Systems Planning Data as reported by the PUCT and Energy Velocity Database.
7. Platts BaseCase.

Figure 6 shows how the total amount of installed generating capacity in ERCOT may change, relative to the amount of existing capacity in 1995, if all currently announced new capacity were ultimately brought into commercial operation. It shows that 26,721 MW of additional capacity has already been added to the ERCOT system since 1995, another 6,438 MW are under construction, and an additional 25,479 MW have been announced. After factoring in mothballed and retired plants, this additional capacity could ultimately raise the total generating capacity of ERCOT to 104,437 MW, up more than 88 percent since 1995.

Figure 6

Summer Capacity Changes to Generation Capacity in ERCOT Since 1995



Notes:
1. Wind generation is discounted to 8.7% of summer capacity to reflect ERCOT's treatment of wind generation in its reserve margin analysis.
2. Capacity resources do not include DC Ties.
3. Not all "Announced" Nuclear Generation has a completed Nuclear Regulatory Commission Application.
Source: Analysis of ERCOT Operations and Systems Planning Data as reported by the PUCT and Energy Velocity Database and ERCOT, "Report on the Capacity, Demand, and Reserves in the ERCOT Region," May 2008.

Capacity margins: In light of these substantial capacity additions, reserve margins are adequate at present. ERCOT has reported actual reserve margins[57] for summer peak periods at levels above its "target" of 12.5 percent:

ERCOT Reserve Margin
(Actual, Unless Otherwise Noted)

2002	35.6%
2003	26.7%
2004	25.2%
2005	16.5%
2006	16.4%
2007	14.6%
2008	13.8% (projected)

Investment in Transmission: Significant new investment in the transmission system has taken place over the past few years in ERCOT.

ERCOT Transmission Improvements
($ million)[58]

2002	$400.9
2003	$424.7
2004	$360.1
2005	$557.4
2006	$749.4
2007	$919.5

Cumulatively, this recent investment totals $3.4 billion in the past six years. These investments have resulted in major additions of miles on the ERCOT Texas transmission grid – with relatively high levels of incremental enhancements both in absolute terms and compared to what has occurred in some other regions of the U.S. in the past decade.[59]

[57] ERCOT, "2006 Annual Report," May 2007, p. 14, and ERCOT, "2007 Annual Report," May 2008, pp. 2, 15.

[58] ERCOT, "2006 Annual Report," May 2007, p. 14; ERCOT, "2007 Annual Report," May 2008, p. 15.

[59] Taking the size of the region's load into account, ERCOT's investment is relatively high. For example, ISO-NE reports that just $1 billion has been spent on regional transmission over the past eight years combined (2000-2007), amounting to an average of $125 million annually. ERCOT's $3.4 billion transmission investment over the last six years combined (2002-2007) amounts to an average of approximately $569 million annually. Taking the ratio of average annual investment to 2007 summer peak load in each region (62,188 MW in ERCOT and 25,773 MW in ISO-NE), indicates that annual transmission investment per MW of peak demand has been nearly 90 percent higher in ERCOT than in ISO-NE ($9,144 per MW in ERCOT versus $4,850 per MW in ISO-NE). Similarly, while PJM has authorized over $7 billion in transmission investment between 2000 and 2006 (corresponding to an annual average of $1 billion), its larger peak load (139,428 MW in 2007) indicates that it is behind ERCOT in terms of load-weighted investment in transmission, with annual transmission investment per MW of peak demand more than 25 percent higher in ERCOT than in PJM ($9,144 per MW in ERCOT versus $7,172 per MW in PJM). ISO/RTO Council, "Progress of Organized Wholesale Electricity Markets in North America: A Summary of 2006 Market Data from 10 ISOs & RTOs," October 16, 2007, p. 5. (Note that ISO-NE reports that four major 345-kilovolt (kV) transmission projects have been successfully constructed and put into service in four states, and another two major 345-kV transmission projects are under construction in two states. Additionally numerous smaller projects are being planned. Statement of ISO-NE, "Regional System Planning Spurs Major Investment in New England's Transmission System: ISO-NE to Conduct

Figure 7 shows the circuit miles of new transmission added[60] in ERCOT prior to and following restructuring in Texas. In 2001, there were approximately 385 circuit miles of transmission added. This number jumped 21 percent in 2002 (to 466 circuit miles), and another 66 percent from 2002 to 2003 (to 775 circuit miles). From 1995 through 2005, ERCOT's total circuit miles of high-voltage transmission lines grew by 21 percent – a higher rate of additions than in most other electrical regions of the U.S.[61]

Significant new investment in transmission is also expected to continue in the future. ERCOT's 2007 "Electric System Constraints and Needs" report notes that $3 billion in proposed transmission projects have been planned for the next five years, with these projects expected to add 2,538 miles of transmission lines and additional autotransformer capacity. Of particular note are two new proposed 345-kV transmission lines and a switching station for the West Texas region to accommodate approximately 6,500 MW of wind generation that is installed or has completed an interconnection agreement.[62] In August 2008, the PUCT approved plans for new transmission facilities to transmit a total of 18,456 MW of wind power from West Texas and the Texas Panhandle to metropolitan areas of the state. The estimated cost is approximately $5 billion and was one of four scenarios ERCOT proposed in response to a 2005 legislative mandate that directed the PUCT to select the most productive wind zones in the state and devise a transmission plan to move power from these zones to the various population centers in Texas.[63]

Studies that Evaluate the Economics of Additional Transmission Expansion," NARUC Winter Committee Meeting and 2008 National Electricity Delivery Forum, February 21, 2008.)

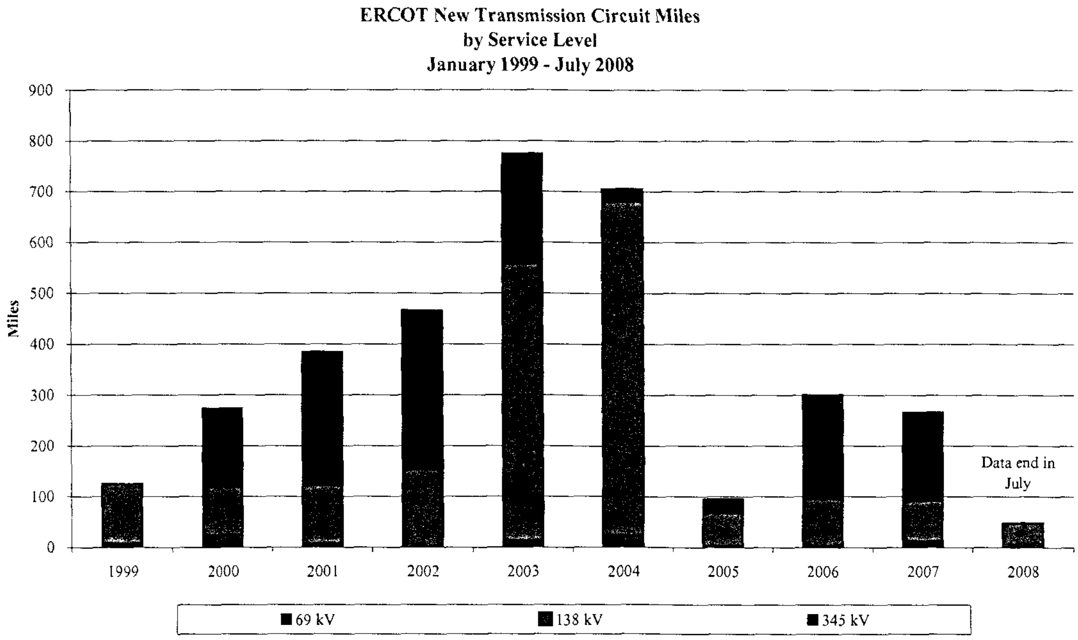
[60] Excluding circuit miles rebuilt, reconstructed, or upgraded.

[61] This refers to transmission lines of 230 kilovolts ("kv") and above in the United States. For example, over the same period, the following other regions had lower percentage increases in total circuit miles (230 kv.and above): the Western region (the "Western Electric Coordinating Council" or "WECC") increased by 7 percent; Florida (the "Florida Reliability Coordinating Council" or "FRCC") grew 8 percent; the Northeast (the "Northeast Power Coordinating Council" or "NPCC") had no increase; and the MidWest Reliability Organization ("MRO") grew by 13 percent. NERC, "High-Voltage Transmission Circuit Miles (230kV and above)," 1995-2004, 2005, available at http://www.nerc.com/files /High-Voltage_Transmission_Circuit_Miles_2005.doc, available at http://www.nerc.com /files/Historic TotalMiles_95-04.doc.

[62] ERCOT, "Report on Existing and Potential Electric System Constraints and Needs," December 2007, pp. 5-6.

[63] PUCT Order in Docket No. 33672. See PUCT, Press Release, "Texas Public Utility Commission Approves Wind Transmission Plan," July 17, 2008, available at http://www.puc.state.tx.us/nrelease/2008/071708.pdf.

Figure 7



Notes:
1. Data do not include transmission circuit miles rebuilt, reconductored or upgraded.
2. Dates are based on "Actual In-Service Date," as reported. Data include completed projects as of August 1, 2008.
Source: ERCOT Operations and System Planning Data, Transmission Project and Information Tracking Database.

Demand-Response Infrastructure: Texas has focused its attention on developing rules in ERCOT's market to create incentives for development of demand-side resources and demand response. Customers with curtailable and interruptible service compete in the markets for balancing energy and ancillary services that were initially designed for supply-side resources.[64] Industrial chemical and refinery loads with relatively predictable load patterns have participated under the new market structure, and the grid operator's ability to interrupt these customers' loads contributes over 1,600 MW of ancillary services (operating reserves) to the ERCOT market.[65] Other programs for "advanced metering" investments are currently in the beginning stages of development.[66]

Reasons for Texas's Success?

During the second half of the 1990s when Texas was actively discussing whether and how to restructure its electric industry, the state became a target of interest among investors in merchant generation. Like many of the other regions – including California

[64] Jay Zarnikau et al., "Industrial Energy Consumer Response to Wholesale Prices in the Restructured Texas Electricity Market," Draft February 2005, p. 3.

[65] Jay Zarnikau et al., "Industrial Energy Consumer Response to Wholesale Prices in the Restructured Texas Electricity Market," Draft February 2005, p. 3.

[66] PUCT Project #34610 (Implementation Project Relating to Advanced Metering) available at http://www.puc.state.tx.us/electric/projects/34610/34610.cfm.

and many parts of the Northeast – where such discussions were taking place, Texas drew the attention of power plant developers. At the time, expectations of low natural gas prices combined with availability of power plant technology with relatively low capital costs made new gas-fired power plants economically attractive for merchant plant development in these "restructuring" regions generally. Texas had the added features of local sources of natural gas, a fast-growing economy, a political climate relatively favorable to developing and permitting power plants, and environmental imperatives that pressured for cleaner air. These conditions explain the high levels of capacity additions during the second half of the 1990s.

Texas's transmission investments have also remained strong, largely as a function of ERCOT's proactive inter-connection and cost-allocation policies. As discussed more fully earlier, unlike in some other jurisdictions, in Texas, new generation facilities pay only for the costs of interconnecting with the transmission network and not for "deep" interconnection. In addition, transmission planning is done by ERCOT and not by one of the state's utilities. These policies have ensured that new entrants face relatively low transmission-related barriers to entry, and that market participants are given equal access to the transmission system with an opportunity to compete with other generators for loads.

Prices

What Has Happened in Texas?

Although too often we tend to think about prices in terms of whether they went up or down, looking at prices in that way is not particularly helpful in examining whether prices are at appropriate levels.

For one thing, the prices of fossil fuels used to generate a substantial portion of power in the state have increased significantly since 1999 when Texas passed SB7. Whether in a competitive market or a regulated industry, electricity prices generally track changes in fossil fuel prices,[67] since fuel cost is a major cost of producing electricity.[68] As of May 2008, nearly two-thirds of ERCOT generating capacity and half of its energy production came from natural gas.[69] Natural-gas-fired power plants set the market price of wholesale power more than 90% of the time.[70] Figure 8 shows the increases in natural gas

[67] See, for example, the discussion in Susan F. Tierney, "Decoding Developments in Today's Electric Industry — Ten Points in the Prism," paper prepared for the Electric Power Supply Association, October 2007, Executive Summary and Section 1 in particular.

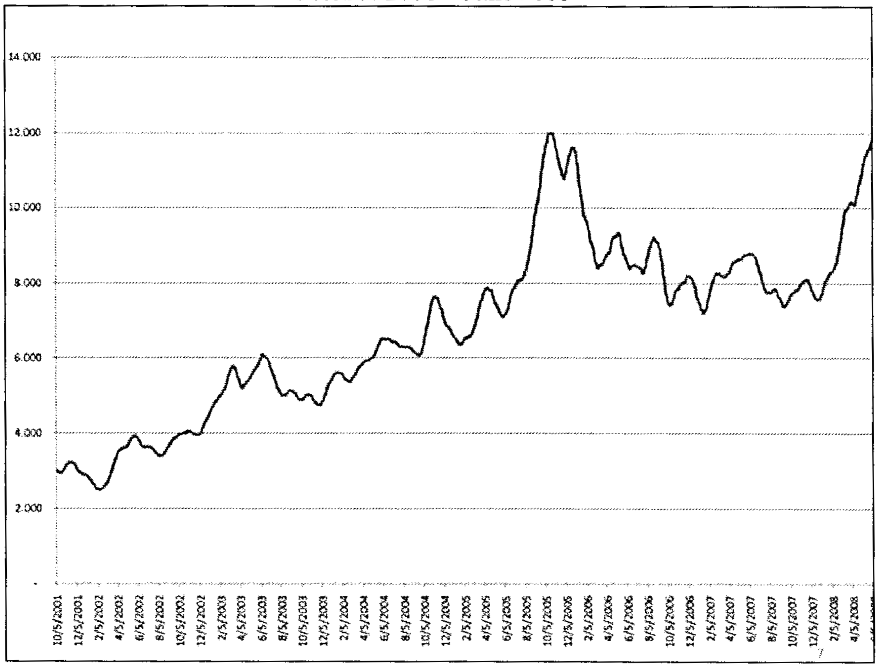
[68] This is true for power plants that use fossil fuels (e.g., coal, natural gas, oil, biomass); it is not true for forms of electricity with very low or no fuel cost (e.g., nuclear, wind, solar, hydroelectric power).

[69] In ERCOT Texas, over 80 percent of electricity produced in 2007 came from fossil fuel power production (with 46 percent from natural gas-fired power plants, and 37 percent from coal-fired power plants). Nuclear generation accounted for 13.6 percent of power produced, with wind supplying 2.1 percent and water supplying 0.2 percent of power. 65 percent of generating capacity was natural-gas-fired power plants, with 46 percent of energy produced from these same generating facilities. ERCOT, "2007 Annual Report," May 2008, p. 2

[70] This estimate is based on a 2004 Henwood study, quoted on page S-60 of the Prospectus of NRG Energy, Inc., filed under SEC Rule 424B5, on January 26, 2006, available at http://www.secinfo.com/dsvr4.vNq.htm.

prices that have occurred since the fall of 2001, with significant increases occurring since the competitive markets opened in Texas in 2002. Focusing on the period from 2003 through 2007, Figure 9 (from the 2007 "State of the Market Report" for ERCOT) compares ERCOT's all-in wholesale electricity price to the price of natural gas and indicates how the two track each other during this recent period.

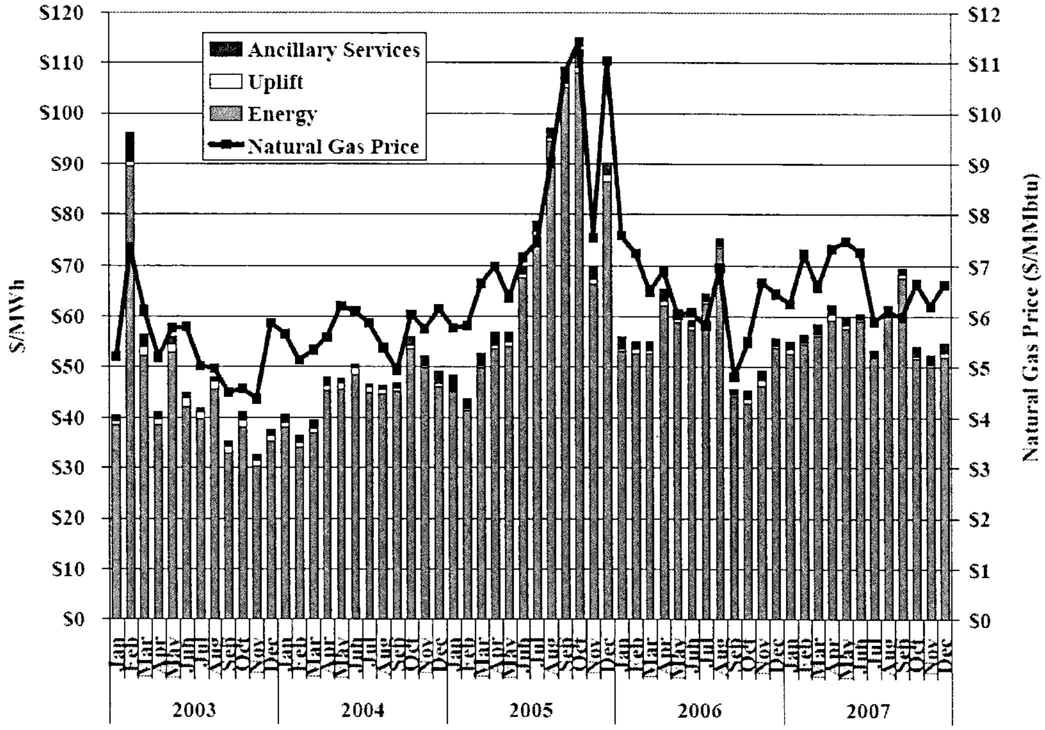
Figure 8
Natural Gas Prices: 20 Day Average
October 2001 – June 2008[71]



71 Barry Smitherman, Chairman, PUCT, Presentation to the House Regulated Industries Committee, June 23, 2008.

Figure 9

**Average All-in Price for Electricity in ERCOT
2003 to 2007**



Source: Potomac Economics (ERCOT Independent Market Monitor), "2007 State of the Market Report for the ERCOT Wholesale Electricity Markets," August 2008, p. xi.

Additionally, the costs of various other goods and services (such as construction materials, steel, aluminum, copper, concrete, and skilled labor) needed to produce electricity have risen dramatically in recent years, as a result of world-wide increases in demand for these important inputs to investment in power plants and transmission/distribution equipment. For example, the Energy Information Administration ("EIA") reports that while steel, cement, and concrete prices followed a general downward trend from the late 1970s through 2002, since then, iron and steel prices have increased by 9 percent from 2002 to 2003, an additional 9 percent from 2003 to 2004, and another 31 percent from 2004 to 2005. Cement and concrete prices have shown similar trends, although with smaller increases, from 2004 through 2006. EIA's cost index for construction materials has shown an average annual increase of 7 percent between 2004 and 2006 in real terms, whereas it had shown an average annual decrease of 0.5 percent over the past 30 years.[72] These increases in underlying cost of materials

[72] EIA, "Impacts of Rising Construction and Equipment Costs on Energy Industries," Annual Energy Outlook 2007, available at http://www.eia.doe.gov/oiaf/aeo/otheranalysis/cecei.html.

needed to construct and operate many parts of the power system have shown no sign of abating. In February 2008, IHS Inc. and Cambridge Energy Research Associates both reported that the cost of new power plant construction in North America increased 27 percent in the last 12 months and 19 percent in the most recent six months, reaching a level 130 percent higher than in 2000.[73]

Overall, electric companies spent more than $21 billion from 2002 to 2005 to comply with federal environmental laws adopted to address health problems associated with air and water pollution, also contributing to higher electric prices, and companies invested billions more to construct new and primarily natural-gas-fired generating capacity (with relatively low air emissions), including in the state of Texas.[74]

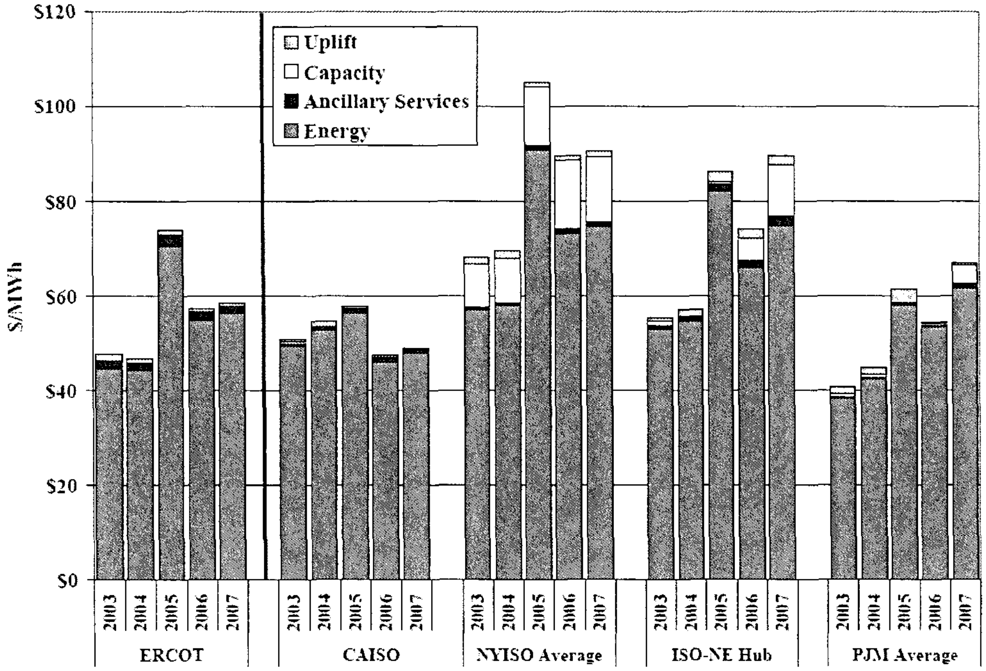
Given these changes in input costs to electricity production, it should come as no surprise then that the wholesale prices of electricity have been rising in recent years, not only in ERCOT but across most parts of the U.S. Figure 10 compares the all-in wholesale price of electricity in ERCOT against four organized electricity markets in the United States: CAISO, NYISO, ISO-NE, and PJM. ERCOT reports that while wholesale electricity markets in the U.S. experienced substantial increases in energy prices from 2004 to 2005 due to increased fuel costs, in 2006, energy prices in the U.S. dropped in every region due to decreased fuel costs. The largest decreases in electricity prices in 2006 occurred in ERCOT, with its ability to adapt relatively quickly to declines in natural gas prices "indicating natural gas resources are on the margin more frequently in this market than other markets."[75] In 2007, prices increased in all five regions, with relatively small increases in ERCOT, California and New York, and more significant increases in New England and PJM.

[73] IHS Inc, "North American Power Generation Construction Costs Rise 27 Percent in 12 Months to New High: IHS/CERA Power Capital Costs Index," February 14, 2008, available at http://energy.ihs.com/News/Press-Releases/2008/North-American-Power-Generation-Construction-Costs-Rise-27-Percent-in-12-Months-to-New-High-IHS-CERA.htm

[74] Rebecca Smith, "Court Decisions May Aid Some Utility Profits in Long Term," *The Wall Street Journal Online,* April 3, 2007.

[75] As noted, "natural gas resources are on the margin more frequently in this market than other markets." Potomac Economics (ERCOT Independent Market Monitor), "2006 State of the Market Report for the ERCOT Wholesale Electricity Markets," August 2007, p. xi.

Figure 10
Comparison of All-In Prices across Markets
2003 to 2007



Source: Potomac Economics (ERCOT Independent Market Monitor), "2007 State of the Market Report for the ERCOT Wholesale Electricity Markets," August 2008, p. xii.

Retail prices are affected not only by changes in the prices of wholesale power, but also by changes in the delivery costs charged by TDUs and in the REP's own internal costs. TDU delivery charges have risen since the beginning of competition. Together, overall price increases in both supply and delivery costs have meant that retail consumers see higher prices today than they did just prior to the start of competition (i.e., regulated rates in effect in December 2001). It is likely, though, that prices in Texas would have risen even in the absence of restructuring, just as they have in states that did not restructure their electric industries.[76]

To examine whether there might be a price advantage today relative to what regulated rates would have looked like in Texas without competition, a "proxy regulated rate" was developed and compared to retail rates currently in effect in parts of ERCOT Texas. The starting point of the "proxy regulated rate" was the rate in effect (in the areas now served by Centerpoint and Oncor) at the end of December 2001, on the eve of competition beginning in Texas. In order to serve as a proxy for a regulated rate in Texas today, the December 2001 rate was adjusted for changes in various underlying costs that have

[76] See, for example, my analysis comparing electricity prices in restructured states versus those that retained their traditional electric industry structure, in Susan F. Tierney, "Decoding Developments in Today's Electricity Industry - 10 Points in the Prism," paper prepared for the Electric Power Supply Association, October 2007, p. 10.

occurred since then.[77] Then, comparing current retail electricity prices in Texas, on the one hand, to the "proxy regulated rates" for 2008, would allow a general comparison of retail electricity prices "with" and "without" competition.

This analysis suggests that retail electricity consumers in Texas have fared relatively well under competition. In both the Dallas-Fort Worth and Houston areas, the "proxy regulated rate" (over 20 cents/kWh) would be approximately double what the rate was in 2001.[78] By contrast, under competition, the average August 2008 residential rate[79] in the Dallas-Fort Worth area was approximately 15.3 cents/kWh and in the Houston area was 16.1 cents/kWh. During the same month, the lowest-priced product available was 13.4 cents/kWh in the Dallas-Fort Worth area and 14.2 cents/kWh in the Houston area (see Figure 11). So this analysis suggests that while residential prices have risen in Texas since the start of retail competition, customers now have more options at lower prices than they would have had under the single regulated priced product.

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[77] The rate in effect on 12-31-01 was adjusted to capture the cost (price) impacts of the following factors:

(a) changes in fossil fuel prices (to reflect the expectation that regulated rates would have included a fuel-adjustment-clause that would have permitted changes in fuel prices to flow through to customers), taking into account the mix of fuel costs used to generate electricity (which, for TXU, now the service territory of Oncor, for example, were approximately 79 percent natural gas, 18 percent coal and 3 percent nuclear);

(b) changes in labor-related portion of the rates (to reflect an expectation that rate cases since 2001 would have allowed for changes in labor-related expenses), with the labor costs in 2001 updated based on the Handy-Whitman Index for labor; and

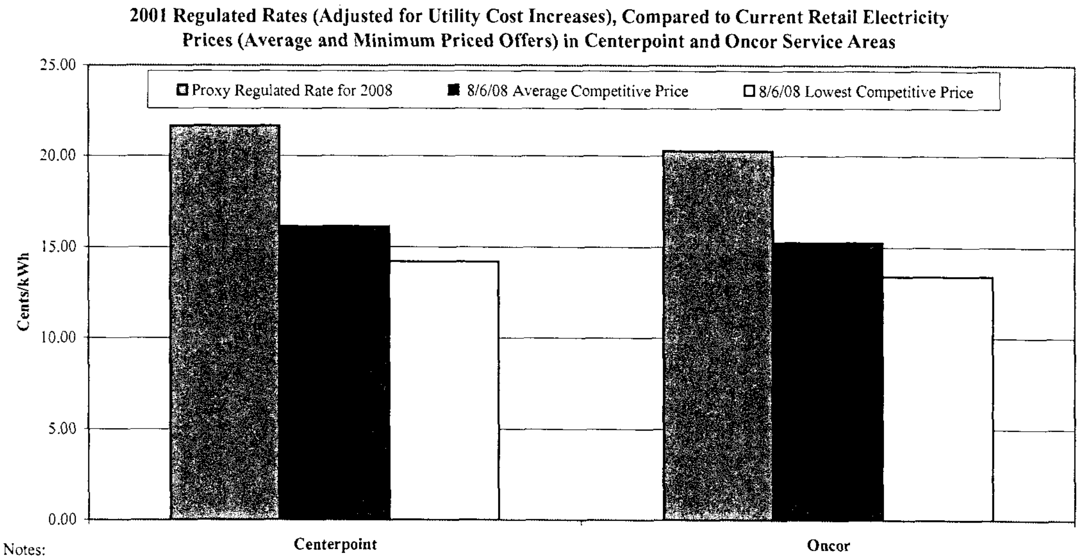
(c) changes in the capital portion of base rates (to reflect the expectation that service-territory growth would have led to investments in new plant), using a method that started with net plant in service as of 2001, adjusted for cost increases based on the Handy-Whitman Index for utility plant

Information on 2001 rates was derived from various contemporaneous PUCT filings; adjustments to base rates used the Handy-Whitman Indices for South Regional.

[78] In December 2001, the average residential rates were: 10.40 cents/kWh for Houston Light and Power ("HLP") customers (now customers served in Centerpoint service area), and 9.67 cents/kWh for TXU customers (now customers served in Oncor service area). As shown in Figure 11, the adjusted rates for 2008 were calculated to be: 21.67 cents/kWh for HLP customers and 20.28 cents/kWh for TXU customers. The different impacts (from 2001 to 2008) for the two companies' rates reflect different fuel mixes and composition of base rates (i.e., plant versus labor costs in base rates).

[79] This reflects the price for a product with a one-year term and less than 5 percent renewables.

Figure 11



Notes:
1. The Proxy Regulated Rates for 2008 represent the 12-31-01 regulated retail rate in effect on 12-31-01 adjusted to capture the cost impacts of changes in fossil fuel prices and changes in labor-related and plant-related portions of base rates.
2. Current prices are the average and the minimum retail prices of contracts that are 12 months and have less than 5% renewable found on the Power to Choose Website for the Centerpoint and Oncor Regions on August 6, 2008.
3. The Centerpoint 12-31-01 adjusted regulated rate is based on HLP's 12-31-01 regulated retail rate. The Oncor 12-31-01 adjusted regulated rate is based on TXU's 12-31-01 regulated retail rate
Sources: Information on 2001 rates was derived from various contemporaneous PUCT filings; adjustments to base rates used the Handy-Whitman Indices for South Regional. 2008 price information: Power to Choose Website, August 6, 2008, available at http://www.powertochoose.org.

Reasons for Texas's Success

Texas has adopted a set of policies designed to induce market-based investment in generating capacity, which – in the past decade – has involved significant investment in capacity additions that use natural gas as a primary fuel. Underlying price increases in natural gas (as in other fossil fuels) in the past few years have meant that electricity prices in ERCOT's wholesale market have risen and fallen as those natural gas prices have changed, just as those impacts have occurred in the other organized RTO markets shown on Figure 10. (Note too that price increases have also occurred in states with traditionally regulated industry structures, as well.) These changes in wholesale prices have been tracked to a large degree by changes in retail prices of electricity to customers located in the ERCOT part of the state. Given the structure of retail pricing in ERCOT Texas, this relative tracking of wholesale and retail prices has had upsides and down sides for customers.

As described previously, Texas adopted a different approach than most other states in its transition from a regulated electric industry to a competitive market. One key difference was the way that Texas designed its Price-to-Beat rate, and this assisted the state in actually moving to full retail competition in parallel with wholesale competition. Texas did not establish a multi-year retail price freeze or rate cap, as other states did for their customers that remained on "default" service.[80] When Texas Choice began on January 1,

[80] California, Pennsylvania, Illinois, Rhode Island, to name a few, instituted transition price freezes or rate caps.

2002, the affiliated REPs were required to charge the rate in effect in 1999 (less 6 percent) and adjusted for then-current fuel prices. Just as important, though, the rate was allowed to be adjusted over time as changes occurred in the market prices for fuels or purchased power. This allowed the PTB rate to rise as wholesale power market prices rose.

This had two important features. It caused Texans to see prices that tracked real-world conditions, and assured that the transition period – the five-year period from 2002-2006 when PTBs were in place – would actually transition consumers to a new industry model rather than simply mask price fluctuations in underlying electricity markets leading to rate shock. Also, it offered competitive suppliers a legitimate chance to offer an attractive price relative to the PTB, since the affiliated REPs were also charging a price that reflected conditions in the wholesale markets in which all suppliers were obtaining their generation supplies. Many other states have found that at the end of their multi-year transition period in which rates were capped and eventually diverged dramatically from the underlying changes in the price to generate electricity, that not only had a competitive retail market failed to develop (since competitive suppliers could not compete against a below-market "default service" price) but also that consumers were ill-prepared to transition smoothly to a competitive market.

Given the structure of retail pricing in ERCOT Texas, this relative tracking of wholesale and retail prices has had upsides and down sides for customers. The reality of higher prices of key inputs (e.g., natural gas) to the cost of producing electricity meant that the Texas model had advantages from an economic efficiency point of view. Although few customers would actually prefer to see their prices rise, the changes occurred gradually and visibly in Texas and allowed customers to make adjustments over time.

Customers in Texas had the price signal to allow them to make their own decisions about using electricity and to rely on offerings from competitive suppliers in making their generation supply choices. As shown in the table below, in states with capped rates or rates reflecting long-term contracts, customers did not receive timely price signals and customers used more electricity year after year even though the real cost of their consumption was increasing. Contrast this with Texas, where retail consumers had price signals and usage per customer declined over time.

Percent Change in Electricity Consumption per Customer (Weather-Adjusted Average kWh/Customer) 1998 - 2006[81]

Maryland	9%
New Jersey	10%
Pennsylvania	13%
Texas	-10%

Sources: EIA 826 data on usage and customers; NOAA weather data.

Diversity of Retail Electricity "Products," Suppliers and Electric Companies

What Has Happened in Texas?

Compared to traditional electricity service where customers have no choice of their supplier, one indicator of the degree of success in a restructured market is the extent to which customers have choices – among various products, with options among competitive suppliers. As described in a recent report, the early competitive period induced significant interest among competitive Retail Electric Providers:

> As quickly as the market opened, new [competitive REPs] entered it. They came from a variety of backgrounds. First were affiliates of existing ERCOT companies selling outside of their home territories, where they were free to discount the PTB. Second were affiliates of utility holding companies such as Sempra Energy of San Diego (parent of San Diego Gas & Electric) and Constellation Energy of Baltimore (parent of Baltimore Gas & Electric). Third were established independent energy producers such as Dynegy and Calpine who had long sold their output in wholesale markets, and fourth were retailers with non-Texas operations such as renewable power specialist Green Mountain Energy. Finally, there were companies such as GEXA and Texas Commercial Energy, which were specifically created to retail in Texas.[82]

The recent evidence confirms a vibrant level of participation of competitive REPs. Figure 12, below, shows that the number of distinct ("unique") REPs (competitive and affiliated) serving residential customers in Texas held steady between 2002 and the start

[81] Data on kWh sales and number of customers are from EIA's 826 database. Data on weather (degree days) are from the National Oceanic and Atmospheric Administration ("NOAA") for each region (Baltimore for Maryland; Newark for New Jersey; Williamsport for Pennsylvania; and Dallas for Texas) Data used to create a weather-normalized load profile were from proxy retail companies in each of the other states: Baltimore Gas & Electric for Maryland; and First Energy for both Pennsylvania and New Jersey.
EIA 826 Database, available at http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls and http:// www.eia.doe.gov/cneaf/electricity/epa/customers_state.xls.

[82] Robert J. Michaels, "Competition in Texas Electric Markets: What Texas Did Right & What's Left to Do," Texas Public Policy Foundation, March 2007, p. 11.

of 2005, with 10 to 12 unique REPS, but more than doubled from 11 at the start of 2005 to 27 at the end of 2007. Similarly, Figure 13 indicates that many REPs serving residential customers compete in each of the different transmission-and-distribution service territories in Texas, with the number of REPs competing in each service territory remaining relatively constant between 2002 and the start of 2005, and then roughly doubling from early 2005 through 2007.[83] During the same period, there were also increases in the number of electric products – such as "month-to-month" electricity service offers ("plans"), plans with longer contract periods, plans with fixed prices versus prices that adjust up or down over time, or plans based on electricity generated with higher-than-normal amounts of renewable energy – available to residential consumers. Using data for the CenterPoint region to illustrate these trends, Figure 14 shows this increase, with 14 separate products available at the start of 2002, 27 at the start of 2006, and 117 separate products available at the end of 2007.

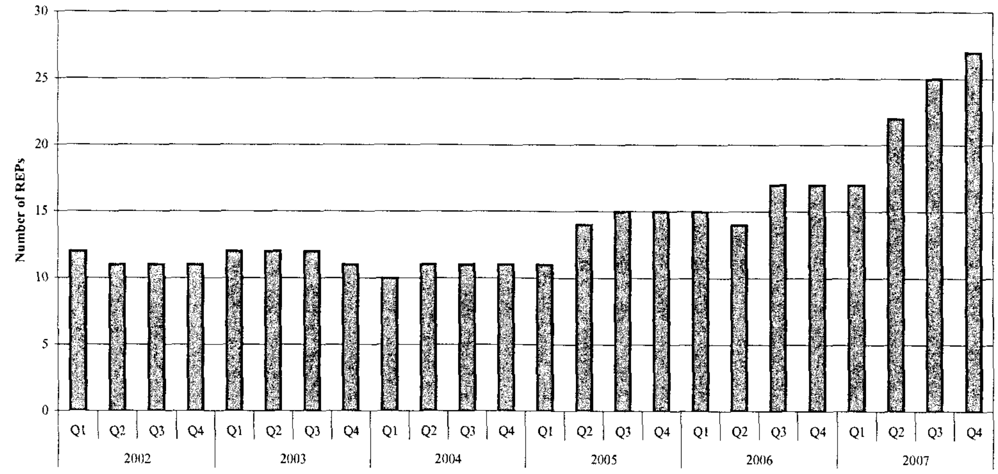
In addition to these direct service providers offering an array of products directly to retail customers, there are many other new companies involved in ERCOT's energy markets. As noted previously, ERCOT listing includes scores of market participants (as of August 2008: 122 certified competitive retailers, 138 unique qualified scheduling entities, 277 load-serving entities, 231 resource entities; and 150 transmission/distribution service entities including municipals and cooperatives), while the PUCT reports 185 registered (active) power marketers in Texas.[84] Additionally, a number of on-line energy marketing firms have emerged to assist customers in shopping among the services of competitive suppliers.

[83] Note than an individual REP may serve multiple service territories. Therefore that REP would be reflected once in Figure 12 but would be reflected multiple times in Figure 13.

[84] ERCOT, "List of Certified Competitive Retailers," http://www.ercot.com/mktparticipants/docs/UpdatedCertifiedCRs%2008192008.xls, updated as of August 19, 2008; ERCOT, "List of Qualifying Scheduling Entities," http://www.ercot.com/mktparticipants/docs/QSEs.xls, updated as of July 23, 2008; ERCOT, "List of Market Participants in ERCOT Region," http://www.ercot.com/mktparticipants/docs/List%20of%20all%20Market%20Participants_0508.xls, updated as of August 8, 2008; PUCT, "Market Directories & Utilities: Electric Companies Serving Texas," http://www.puc.state.tx.us/electric/directories/pm/pm_list.htm.

Figure 12

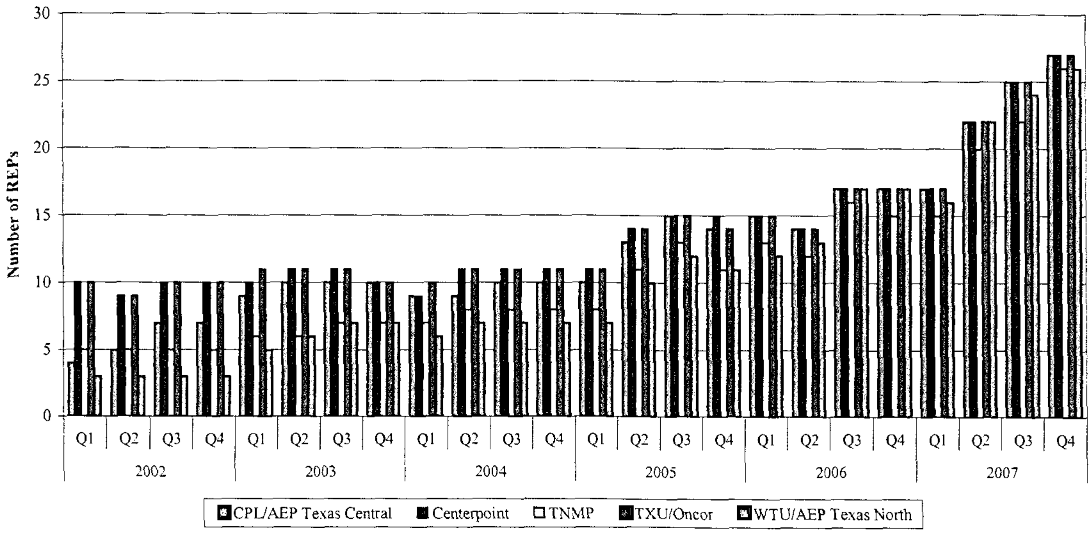
Number of Unique REPs for Residential Service in ERCOT 2002 - 2007



Notes:
1. Data for 2002 through the first quarter of 2005 are provided by the Vector Group using publicly available information reported by the PUCT. Data from the second quarter of 2005 through 2007 are compiled and reported by the Vector Group.
2. Affiliated REPs are included in these data.
3. Data may not include all REPs operating in Texas.
4. The SESCO service area has been excluded due to limited data availability.
Source: The Vector Group.

Figure 13

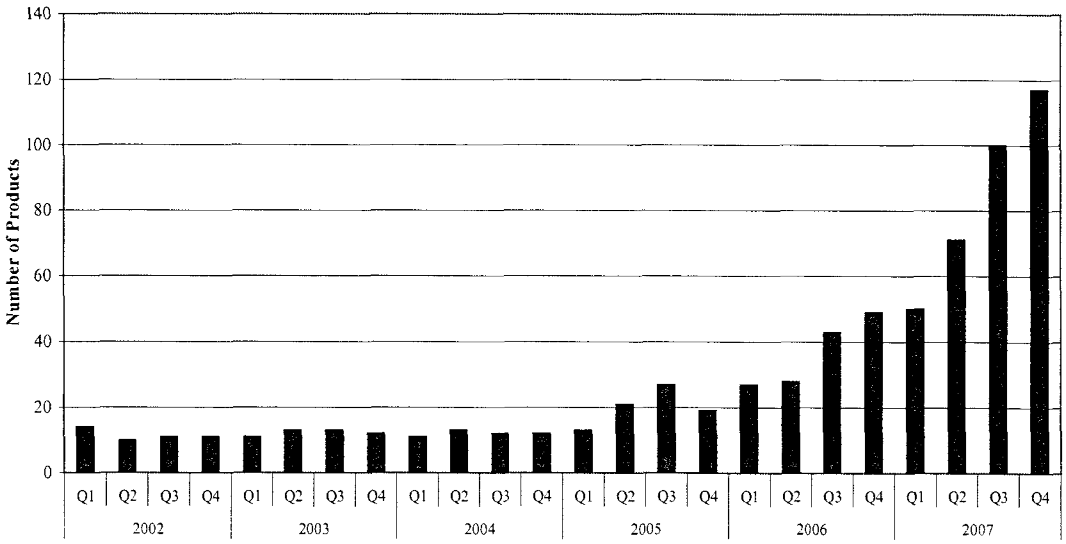
Total Number of REPs by Transmission and Distribution Service Provider for Residential Service in ERCOT 2002 - 2007



Notes:
1. Data for 2002 through the first quarter of 2005 are provided by the Vector Group using publicly available information reported by the PUCT. Data from the second quarter of 2005 through 2007 are compiled and reported by the Vector Group.
2. Data may not include all REPs operating in Texas.
3. The SESCO service area has been excluded due to limited data availability.
Source: The Vector Group.

Figure 14

**Number of Products in Centerpoint for Residential Service in ERCOT
2002 - 2007**



Notes:
1. Data for 2002 through the first quarter of 2005 are provided by the Vector Group using publicly available information reported by the PUCT. Data from the second quarter of 2005 through 2007 are compiled and reported by the Vector Group.
2. Data may not include all REPs operating in Texas.
Source: The Vector Group.

Reasons for Texas's Success?

The retail market design in Texas allowed competitive REPs to have a chance to enter the market even as prices rose in underlying wholesale electricity markets after retail choice began in 2002. The PTB was allowed to adjust up to two times per year in parallel with changes in the price of the fossil fuel (natural gas) used predominantly to generate electricity in ERCOT. This meant that potential suppliers were not disadvantaged by having to compete against a below-market electricity price, and consumers had an opportunity to choose from among a variety of competitive suppliers vying for their business. This stands in stark contrast to the experience of other restructured states, where few competitors have entered the retail market due to conditions in which the chronically below-market "default service" price inhibited the entry of retail market participants. In addition and as previously described, consumers in these states have faced recent "rate shocks," as sudden price increases were introduced when multi-year rate freezes ended and consumers were no longer shielded from market conditions.

Other reasons for Texas's success include the availability of up-to-date information and educational materials for consumers about their options in the retail market place; the centralized switching functions carried out by ERCOT, which lowers barriers to entry for competitors and eases the process for consumers; and a series of policies (including the initial auction of capacity entitlements held previously by incumbent utility companies) that promoted fair competition.

Texas is also able to deal quickly with the business failure of REPs while providing seamless service to customers. For instance, five REPs recently defaulted on their financial obligations to ERCOT, most likely a result of the price spikes in ERCOT due to zonal congestion management in the March–June 2008 time period.[85,86] In Texas, Provider of Last Resort ("POLR") service provides a temporary, transition service allowing customers to continue to receive electric service while they choose a competitive product. Out of 6.5 million customers in ERCOT, about 44,000, or 0.7%, were transitioned to the POLRs during May and June 2008.[87] Almost two-thirds of these customers have already selected other plans or providers.

Environmental Quality and Alternative Resource Development

1. Air Pollution from Power Plants

What Has Happened in Texas?

Over the past decade, Texas's fleet of power plants has grown almost exclusively through the addition of power plants that use natural gas and wind to produce electricity.[88] The entry of significant quantities of low-emitting gas-fired and wind-power generating units into the Texas power market over the past decade has contributed significantly to decreases in emissions rates of key air pollutants in Texas. Figure 15 shows trends in

[85] Note that these REP defaults are another example pointing to the need for Texas to determine more appropriate methods for pricing transmission congestion under the zonal model and to move to a nodal market as soon as practical, as discussed later in this paper.

[86] Higher-than-normal temperatures in April and May led to increased demand in certain regions, and increased zonal congestion on the system. While some regions in ERCOT experienced greater congestion impacts, ERCOT as a whole experienced 14.4 days and 15.3 days of congestion in April and May of 2008, respectively, compared to just 3.6 days and 6.2 for the same months of 2007. (The number of days of congestion for each month were derived by averaging zonal data from pages 11 and 12 of the Barry Smitherman, Chairman, PUCT, Presentation to the House Regulated Industries Committee, June 23, 2008.) By the end of May, two companies (Pre Buy Electric and National Power) had already defaulted; by June 4th, Etricity was the third firm to default on its financial obligations. ("Etricity Brings Defaulting ERCOT Marketer Count to 3," *Restructuring Today*, June 5, 2008.) A fourth company, Sure Electric, failed a week later after its plan to declare bankruptcy was unsuccessful. By the end of the June, another company, Blu Power, had defaulted due to high wholesale power prices, bringing the total number of companies to five. ("Fourth Marketer Stripped of Customers in Challenging ERCOT Market," *Restructuring Today*, June 12, 2008; Elizabeth Souder, "Fifth Texas Retail Electric Provider to Stop Serving Customers," *The Dallas Morning News*, June 30, 2008.) On August 14th, 2008, the PUCT revoked the certificates of four of the five retail electric providers that defaulted on their service obligations. The PUCT has a continuing investigation of the activities of these companies. PUCT Press Release, "PUC Revokes Electric Provider Certificates," August 14, 2008. http://www.puc.state.tx.us/nrelease/2008/081408.pdf.

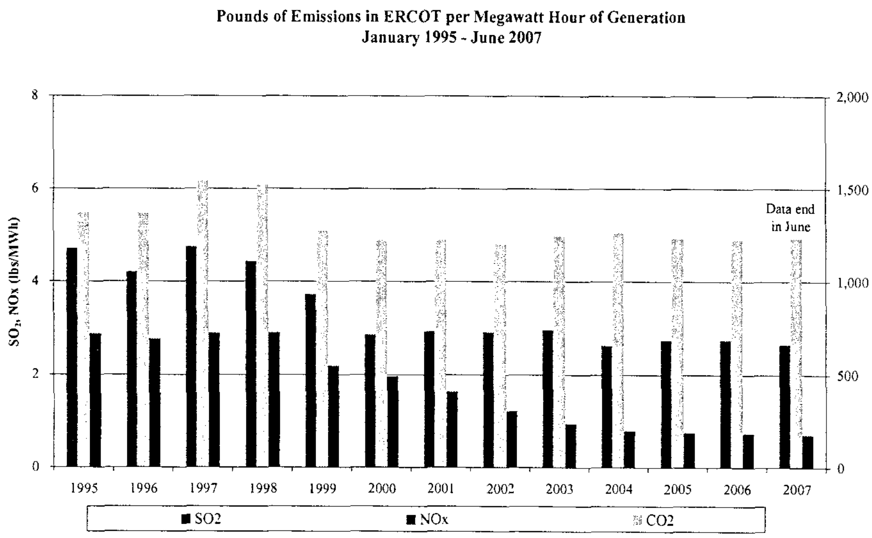
[87] Barry Smitherman, Chairman, PUCT, Presentation to the House Regulated Industries Committee, June 23, 2008; Letter from Bret Slocum to the Commissioners of the Texas PUC, dated August 6, 2008; Elizabeth Souder, "Fifth Texas Retail Electric Provider to Stop Serving Customers," *The Dallas Morning News*, June 30, 2008.

[88] Of the 26,721 MW of capacity added in Texas from 1995 through April 2008, 25,894 MW was from natural gas power plants; 388 MW from wind facilities (note that this 388 MW of wind capacity counted towards resource adequacy is actually tied to 4,457 MW of installed wind capacity actually added); 200 MW from nuclear capacity upgrades; and 147 MW from coal-fired capacity additions). Based on an analysis of ERCOT Operations and Systems Planning Data (as of October 2007), as reported by the PUCT (in November, 2007), and as updated by Energy Velocity Database (as of April 2008).

three types of air emissions from producing electricity (and combusting fossil fuel) in power plants: sulfur dioxide ("SO_2") emissions, carbon dioxide ("CO_2") emissions, and nitrogen oxides ("NOx") emissions. Figure 15 shows that from 2001 through June 2007, regulated emissions of SO_2 and NOx decreased on the basis of emissions-per-unit of electricity produced (i.e., emissions/ megawatt-hour ("MWh"): NOx emissions decreased by more than 56 percent (from 1.6 pounds/MWh to 0.7 pounds/MWh), SO_2 emissions decreased by 10 percent (from 2.9 pounds/MWh to 2.6 pounds/MWh). During the same period (2001-mid-2007), CO_2 emissions per MWh (an unregulated emission in Texas) remained relatively flat, even though it decreased since a decade ago.

Figure 16 shows that in aggregate, between 2001 and 2006, NOx emissions decreased by nearly 50 percent, while SO_2 emissions increased by approximately 5 percent, and CO_2 emissions increased by 13 percent. The increases in SO_2 and CO_2 are due to the substantial growth in electricity production.[89] Had the emissions improvement per MWh seen in the power plant fleet not occurred over the past few years, today's total emissions of NOx, SO_2 and CO_2 would have been much higher. To illustrate this point, Figure 16 also shows trend lines for each pollutant, calculated by using 1995 through 1999 (the year when SB7 was enacted) data to project emissions for the years 2000 through 2007. For each pollutant, the actual emissions in 2007 were substantially lower than what would have been predicted for 2007 based on actual 1995 through 1999 emissions.

Figure 15

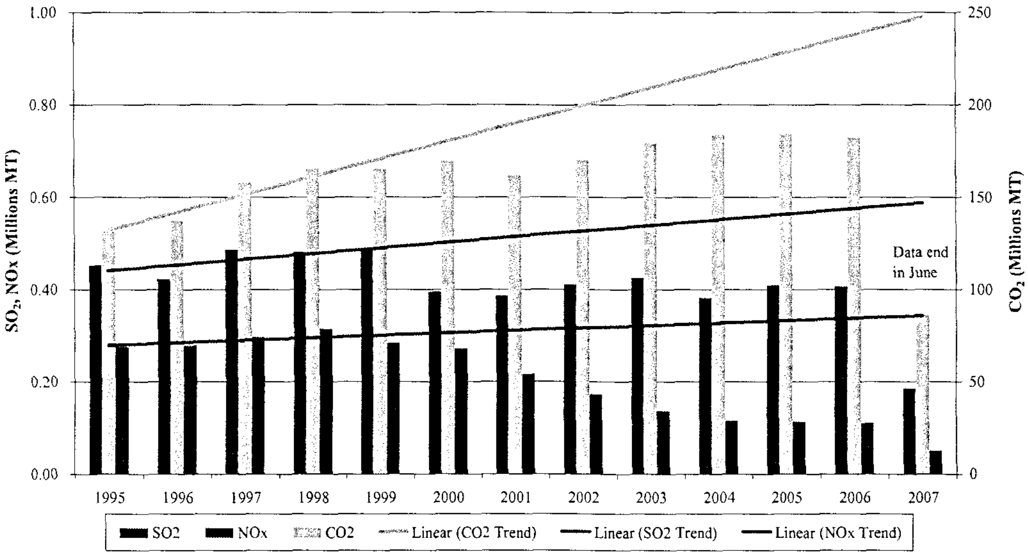


Notes:
1. Data are calculated as total emissions (lbs) divided by total ERCOT actual generation (MWh).
2. Data include plants that operate exclusively in ERCOT, as reported by Platts.
3. Data for 2007 include January - June only.
Source: Platts BaseCase.

[89] For the six-year period from 2002 through 2007, ERCOT energy consumption grew 9.4 percent, from 280.7 GWh in 2002 to 307.1 GWh in 2007. ERCOT, "2006 Annual Report," May 2007, p. 14 and ERCOT, "2007 Annual Report, May 2008, p. 15. In the U.S. electric industry overall, power production rose at two-thirds this rate, growing only 5.3 percent from 2002 through 2006 (or, from 3,858.5 GWh in 2002 to 4,064.7 GWh in 2006). EIA, "Net Generation by Energy Source by Type of Producer," from the Electric Power Annual, October 22, 2007, available at http://www.eia.doe.gov/cneaf/electricity/epa/epat1p1.html.

Figure 16

Total Emissions in ERCOT (Metric Tons)
January 1995 - June 2007



Notes:
1. Data include plants that operate exclusively in ERCOT, as reported by Platts.
2. Data for 2007 include January - June only.
3. Data are converted from pounds (lbs) to metric tons (MT).
4. Trendlines are calculated by using 1995 - 1999 data to project emissions from 2000 - 2007.
Source: Platts BaseCase.

Reasons for Texas's Success?

Among the various goals of Texas's restructuring initiative was a desire to lessen emissions of pollutants from power plants, as a way to assist the state's larger efforts to improve air quality.[90] The addition of substantial generating capacity from gas-fired power plants – facilities that are not only relatively efficient (consuming less fossil fuel per unit of electricity produced) but also use a lower-emitting fuel than coal-fired power plants – was one means to achieving this goal. The state's combination of retail and wholesale market designs enabled markets for the efficient dispatch of gas-fired power generation, with relatively low emissions per Btu of fuel burned in the power plant. The market rules allowed for incremental supplies of relatively low-emitting generation to compete with existing generation located in the Texas market. The electricity generated from wind, of course, comes with no air emissions at all. This new investment in relatively low-emitting generation has been fostered by the many improvements in market elements described above, as well as through the adoption – on two occasions – of

[90] "Air quality concerns run parallel to virtually every aspect of electric utility restructuring efforts, affecting the emerging competitive market structure on numerous levels and presenting challenges to reliability of the bulk power grid." Texas Electric Utility Restructuring Legislative Oversight Committee, "Report to the 77th Legislature," November 2000, p. 67.

increasingly more aggressive renewable portfolio standards (see below), and the cost-allocation policies that led to support for transmission infrastructure development in the state.

2. Wind Development and other Renewable Energy

What Has Happened in Texas?

The growth of Texas's large wind resource is now famous. Whereas a decade or so ago (in 1995), there were virtually no wind turbines operating in the state, by today, a vibrant wind market is on display with still-more development on the horizon. Using nameplate generating capacity as the metric, by the end of 2007 4,457 MW of wind turbines had entered commercial operation, additional projects totaling 3,600 MW had signed interconnection agreements, and another 35,000 MW of wind turbine projects had been announced.[91,92] There is no other part of the country with so much wind capacity in and/or entering the market, in spite of California's head start over the past two decades.[93]

Texas's success in developing wind turbine capacity exceeds the experience of other states, not just because of the large wind resource in the state, but because the state's market structure, renewable energy, and transmission policies provide an attractive environment for wind development. Developers of wind power in the state view these policies favorably, as noted in the following statements:

- "From the point of view of permitting, Texas 'is by far the most friendly state;'"[94]
- "Compared to other states and other markets, the siting regime in Texas for all generation resources is very favorable — but particularly for wind;"[95]

[91] The source of the commercially operating wind an analysis of ERCOT Operations and Systems Planning Data (as of October 2007), as reported by the PUCT (in November, 2007), and as updated by Energy Velocity Database (as of April 2008). The source for the other statistics is Mike Sloan, The Wind Coalition, "Competitive Renewable Energy Zones (CREZ) in Texas: Increasing Renewable Energy in the Western Grid Summit (WGA / NWCC)," September 28, 2007.

[92] As noted previously, the capacity shown in Figures 3 and 6 suggests a lower amount of wind capacity has been added in ERCOT than is indicated here, using summer capacity value of wind turbines. The capacity amounts in Figures 3 and 6 reflect the *capacity value* of generating units as counted by ERCOT for resource adequacy analyses (i.e., reserve margin planning purposes). For those purposes, ERCOT discounts the capacity of wind units to 8.7 percent of summer capacity value, to reflect the amount that can be relied upon in the peak hour for capability planning purposes. The summer capacity values are relevant here for indicating the significant amount of development of wind resources, which are capable of providing power in other periods besides the peak hour.

[93] "According to the American Wind Energy Association, by the end of 2006 Texas overtook California as the Nation's leader in wind energy capacity." EIA, "Renewable Energy Trends in Consumption and Electricity, 2005," July 2007, p. 9.

[94] John Calaway, Babcock & Brown's Chief Development Officer of wind in North America, as quoted in "Wind Developers Deem Texas Best US Market," *Electric Power Daily*, March 1, 2007.

[95] Mark Bruce, director of market affairs at FPL Energy, as reported in "Wind Developers Deem Texas Best US Market," *Electric Power Daily*, March 1, 2007.

- "We have a functional market structure...we've been able to do things with wind energy in Texas that we can't do in other parts of the country."[96]

Development has also been bolstered by the commitment of large (and even small) electric customers to obtain substantial amounts of their electricity from wind generation. For example, the Environmental Protection Agency's Green Power Partnership releases a "Top Partner" list that identifies the annual leading green power purchasers across individual sectors. As of April 28, 2008, several Texas cities and one of its universities made the top lists by deriving a certain percentage of their power from wind. On the National Top 25 List, the City of Dallas earned the 9th highest spot on the list by supplying 40 percent of its power use from wind. Close behind, the City of Houston ranked 12th, relying on wind power for 20 percent of its electricity needs. Of the top ten universities nationally, Texas A&M ranked 7th by obtaining 15 percent of its electricity from wind.[97]

The development of wind generation resources has been the primary means by which Texas has diversified its electricity mix in recent years. Overall, the region is heavily dependent upon natural gas, which in 2007 produced nearly half of the power and, in 2006, was the fuel source "on the margin" in ERCOT's balancing market in most hours of the year.[98] The addition of renewables in the future is expected to increase its share of the total mix.

Figure 17 shows that ERCOT has also been successful in developing non-wind renewable generation, albeit to a much lesser extent. Since September 1999, ERCOT has seen the addition of more than 100 MW of installed capacity from renewable sources other than wind (67 MW from landfill gases, 20 MW from biomass, 20 MW from hydro, and 1 MW from solar).[99]

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[96] Mark Bruce, director of market affairs at FPL Energy, as reported in "Wind Developers Deem Texas Best US Market," *Electric Power Daily*, March 1, 2007.

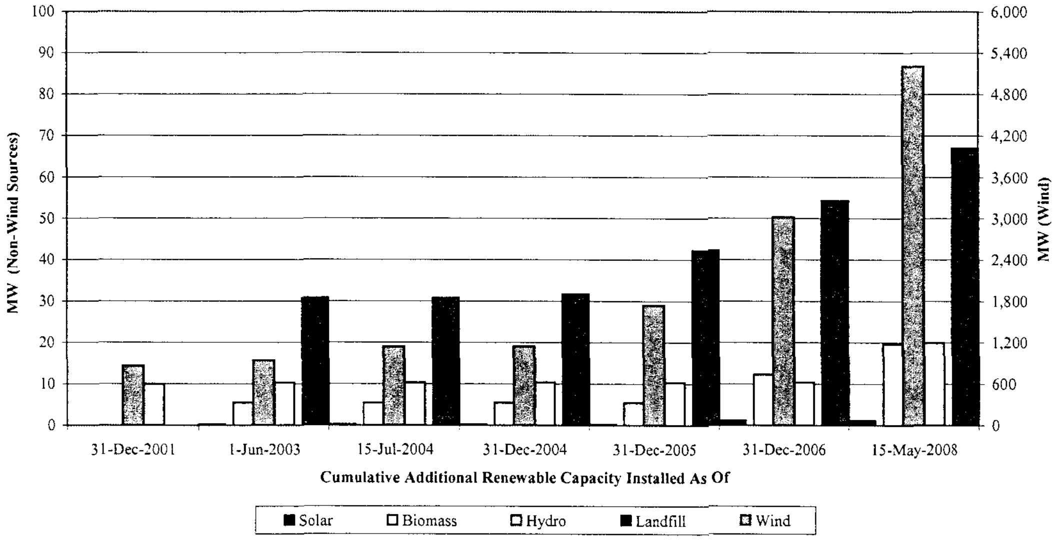
[97] Environmental Protection Agency Green Power Partnership, "Top Partner Rankings," as of April 8, 2008, available at http://www.epa.gov/greenpower/toplists/index.htm.

[98] ERCOT, "2007 Annual Report," May 2008, p. 2 and Barry T. Smitherman, "The Need for New Electric Generating Capacity in the Texas Electric Market," Presentation to the Senate Committee on Natural Resources, July 13, 2006 available at http://www.puc.state.tx.us/about/commissioners/smitherman/present/pp/BTS_SCNR_071306.pdf.

[99] Texas Renewables, "Existing/New REC Capacity Report," available at https://www.texasrenewables.com/publicReports/rpt5.asp.

Figure 17

ERCOT Renewable Capacity Installed After September 1999
by Fuel Type
2001 - May 2008



Notes:
1. Data for 2008 are reported as of May 15, 2008.
2. Capacity additions after September 1999 reflect additional installed capacity that is participating in the REC program and may not reflect all additional installed capacity.
Sources:
1. 2008 data is from the Existing/New REC Capacity Report, available at www.texasrenewables.com, as of May 15, 2008.
2. 2001-2006 data are from the Annual Reports, available at www.texasrenewables.com.

Reasons for Texas's Success?

Several factors have contributed to Texas's success in developing wind turbine and other renewable capacity. The enormous size of the state's available wind resource, combined with Texas's favorable transmission investment/cost-allocation policies, have helped to enable Texas wind developers to bring projects successfully to commercial operation. Furthermore, Texas's vibrant retail market allowed REPs to develop, market and sell differentiated "green" electricity products to an informed and interested set of consumers. Finally, like many states, Texas adopted a Renewable Portfolio Standard ("RPS") as part of its 1999 restructuring law. This mandate helped to jumpstart the market, but it has become evident over the last several years that other factors were as if not more important in allowing Texas to lead the nation in wind development.

Customer Involvement

What Happened in Texas?

One of the metrics easiest to track in examining activity in Texas's retail electricity markets is to observe what customers actually do, once they have the opportunity to choose to buy power from a competitive supplier: Do they stay on the same plan after the option to choose became available?[100] Or do they switch to another plan once they have had the chance to do so?

As shown in Figure 18, below, an ever-increasing share of Texas residential consumers has elected to buy power from a competitive supplier, even during the 2002-2006 transition period when they had the option to take power under "regulated" PTB prices. Figure 18 reports data on the year-end percentage of residential electricity customers in Texas served by a competitive REP since the introduction of competition in 2002. It shows that at the end of 2002, only 7 percent of residential customers were served by a competitive REP; just five and a half years later, at the end of June 2008, however, that number had increased over six-fold, to 43 percent. Moreover, by June 30, 2008, 76 percent of residential consumers in ERCOT had made a choice of a product other than the default rate.[101] This is many times greater than in any other market. These percentages are even higher for larger consumers of electricity – commercial and industrial customers (data not shown).

Overall, a much higher percentage of residential customers in Texas has switched to competitive plans as compared to the patterns in other restructured states. As shown in Figure 19, in 2006, 36 percent of residential customers in Texas received their power from competitive providers, while just 3 percent did in Connecticut, 8 percent did in Massachusetts, 7 percent did in New York, 2 percent did in Pennsylvania and less than 0.1 percent did in New Jersey.[102]

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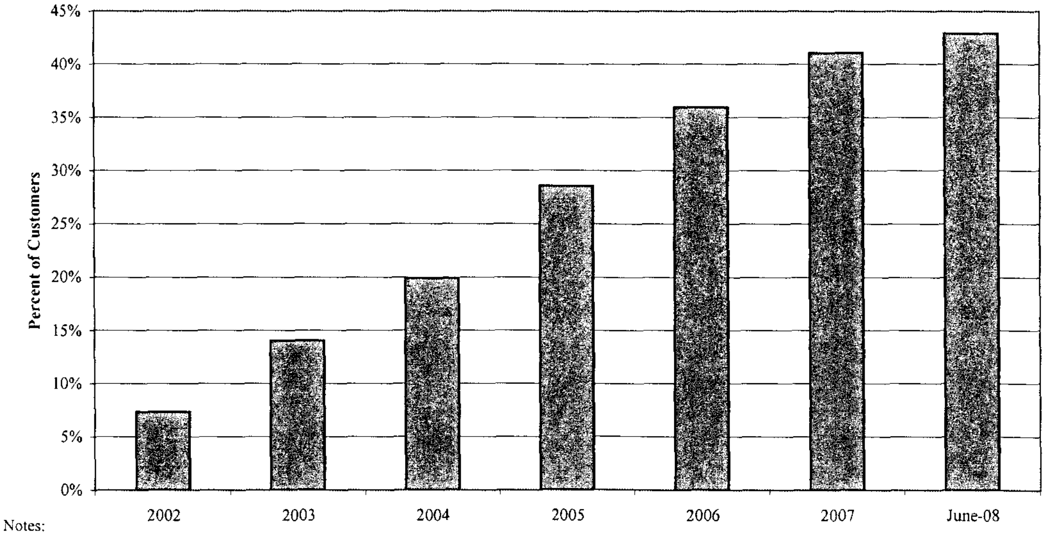
[100] In Texas, this would have been the original affiliated REP; customers who "chose not to choose" in areas of Texas open to competition on January 1, 2002, were served by the affiliate REP of the incumbent utility.

[101] The 76 percent includes residential customers who have either chosen a competitive retailer or an affiliated REP non-PTB product, and POLR transition customers. Letter from Bret Slocum to the Commissioners of the Texas PUC, dated August 6, 2008.

[102] Figure 19 uses EIA's 861 database, which provides a consistent database for comparing migration across the states. This database does not provide the most up-to-date information on migration, however. Therefore, using migration information for each of the relevant states, the migration data for 2007 are: 11.3 percent for Massachusetts (for December 2007); 13.1% for New York (for December 2007); 0 percent for New Jersey; 2.8 percent for Pennsylvania; and 41 percent for Texas. Sources of information: Massachusetts Division of Energy Resources, "2007 Electric Power Customer Migration Data," January 24, 2008, available at http://www.mass.gov/Eoca/docs/doer/2007migrate.pdf; New York State PUC, "December 2007 Electric Retail Access Migration Reports," available at http://www.dps.state.ny.us/Electric_RA_Migration_12_07.htm; New Jersey Board of Public Utilities, "Switching Data: New Jersey Electric Statistics," August – September 2007, available at http://www.bpu.state.nj.us/bpu/divisions/energy/switching.html; Pennsylvania Office of Consumer Advocate, "Pennsylvania Electric Shopping Statistics," January 1, 2008, available at http://www.oca.state.pa.us/Industry/Electric/elecstats/Stats0108.pdf, and Pennsylvania PUC, "2007 Report on Universal Service Programs & Collections Performance," 2007, p. 6, available at http://www.puc.state.pa.us/General/publications_reports/pdf/EDC_NGDC_UniServ_Rpt2007.pdf; Letter from Bret Slocum to the Commissioners of the Texas PUC, dated January 24, 2008.

Figure 18

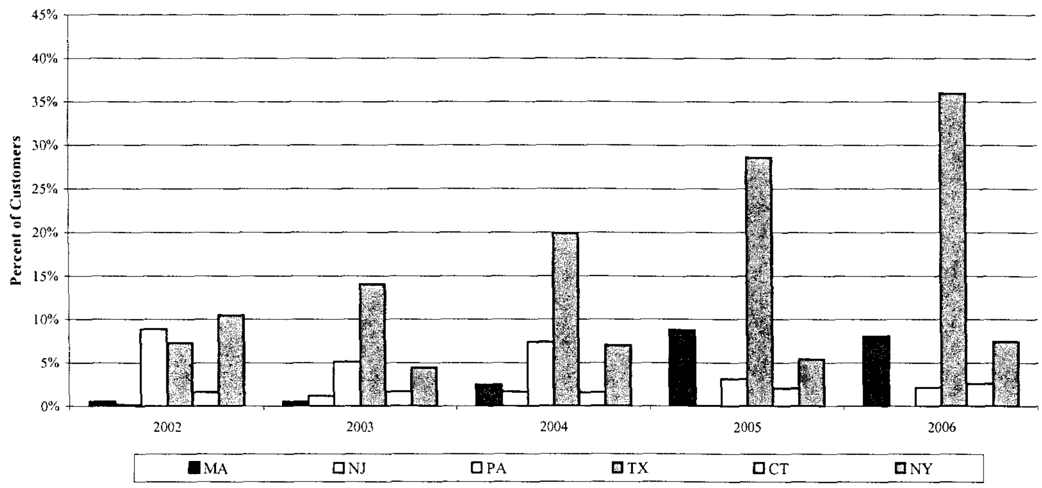
Percentages of Residential Customers with a Competitive REP in ERCOT
2002 - June 2008



Notes:
1. Data represent the percentage of customers with a competitive REP as of December of that year for 2002-2007. Data for 2008 are as of June 30.
2. Data from 2002 - 2005 come from the Texas PUC. Data for 2006 - June 2008 come from ERCOT and are presented as attachments in letters from Bret Slocum to the Commissioners of the PUCT.
Sources:
1. Public Utility Commission of Texas, "Summary of Performance Measure Data," http://www.puc.state.tx.us/electric/reports/RptCard/index.cfm, obtained January 2008. 2. Letters from Bret Slocum to the Commissioners of the Texas PUC, dated March 9, 2007, January 24, 2008, and August 6, 2008.

Figure 19

Percentages of Residential Customers with a Competitive REP
2002 - 2006

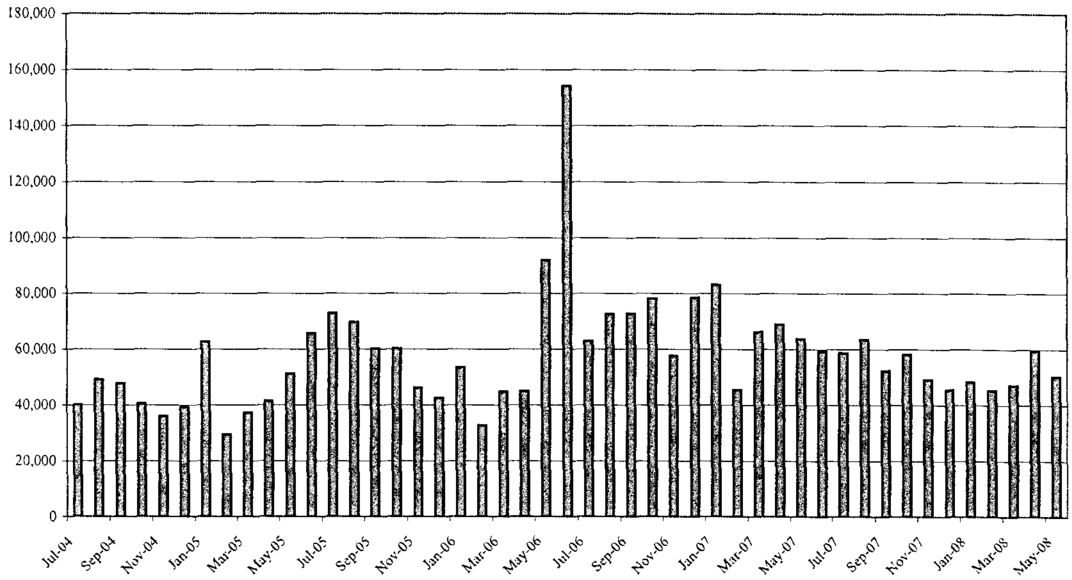


Notes:
1. Competitive REPs are defined as "Power Marketers" for CT, MA, NJ, NY, and PA as reported in the EIA 861 database. The total number of customers served by competitive REPs and affiliated REPs have been estimated by summing the number of customers served by "Power Marketers" and those reported as receiving a "bundled" service from an "Investor Owned" utility.
2. For Texas, data for 2002 through 2006 represent the percentage of customers with a competitive REP as of December of that year. Data from 2002 - 2005 come from the PUCT. Data for 2006 come from letters from Bret Slocum to the Commissioners of the PUCT.
Sources:
1. Energy Information Administration, Form EIA-861, EIA.gov, available at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.
2. Public Utility Commission of Texas, "Summary of Performance Measure Data," http://www.puc.state.tx.us/electric/reports/RptCard/index.cfm, obtained January 2008. 3. Letters from Bret Slocum to the Commissioners of the Texas PUC, dated March 9, 2007.

Customer switching has been relatively strong in Texas over the past few years, as shown in Figure 20. These data (for mid-2004 through May 2008) indicate a relatively high and continuing degree of customer engagement in the retail market.

Figure 20

Number of Switches Made per Month in ERCOT
July 2004 - May 2008



Notes:
1. The date corresponds to the number of switches made in that month.
2. No data exist for September 2005. The values in August and October of 2005 were used to approximate the value in September 2005.
3. As of May 2008, 4,100,715 switches had been made since June 1, 2001.
Sources: ERCOT, "Market Operations Reports," presented at ERCOT Board of Director's Meetings, August 2004 - July 2008.

Reasons for Texas's Success?

Clearly, Texans are aware that their state has an electric industry model in which they are expected to choose their electricity provider, much as consumers normally understand that they have to choose a mobile-telephone service provider, or a plumber, or other providers of service to their home or business. This high degree of consumer awareness is fundamental to any well-functioning market, because without knowledge that a market *exists* where one previously did not, consumers are unlikely to exercise their option to choose.

Among the more significant reasons for the high degree of customer awareness and resulting engagement with the market are three principal factors found in Texas: intense commitment to customer education; direct consumer interaction with their REP; and the relative ease of the process through which consumers switch to alternative providers. While each of these has been mentioned previously, they are important for helping to explain Texas's success:

- **Customer Education**: Texas adopted a deliberate, strong and continuing consumer education effort. SB7 established, and the PUCT has administered, an extensive statewide-customer education campaign to inform retail customers about their choices in the new competitive market. In addition, REPs provide educational material and services to consumers.

- **Direct Consumer Interaction with their REP**: Unlike other states that restructured their electric industries, Texas adopted a model in which the REPs would interact directly with customers, rather than through the local distribution company. This has meant that it is the REP that furnishes the customer with his or her monthly electric bill, receives calls for almost all customer issues (REPs may instruct customers to contact the local distribution company for outages and certain service orders), and otherwise has the direct commercial relationship with the customer. Also key is part of the market design where new customer initiation requires the customer to select its provider. This, combined with other features of Texas's relatively vibrant retail market, has led to a greater understanding among consumers[103] that they have options, that it is their responsibility to choose, and that their primary relationship for electricity service is with their supplier rather than with the local "wires" company.

- **Relative Ease of the "Switching" Process:** Texas adopted a centralized system for administering the processes by which retail customers obtain electric service from a REP. As the centralized registration agent for all of ERCOT Texas, ERCOT has the responsibility to receive and manage the transaction orders to assure that the transactions necessary for customers to receive electric service when they move to a new location (or move out of one) and arrange for power to be supplied by a REP are communicated to all parties. This centralization of "service registration" functions is different than in other states that restructured their retail electricity markets, where these functions are carried out by the local TDU, which can cause the retail provider to build multiple registration systems for a single state. This was an explicit element of the design of the retail market, in which the PUCT desired to reduce the barriers to entry for REPs entering the Texas market.[104] Additionally, it has meant that service connections, switches, etc., involve a relatively smooth process for consumers.

[103] See the further discussion on customer awareness, below.

[104] PUCT, "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2003, p. 19.

Low Income and Other Customer Programs, Services and Protections

What Happened in Texas?

Low-Income and Other Targeted Programs: As part of its electric industry restructuring, Texas included a number of consumer protections and programs to assure that electricity would be broadly available to retail consumers. These programs were funded by a "system benefit charge" paid for by REPs[105] with funds deposited into a "system benefit fund." The system benefit charge is tied to a consumer's usage levels; for a typical household REPs support an annual payment of approximately $9.75 per household to the system benefit fund.[106]

One of the functions supported by the Texas system benefit charge is helping to subsidize the monthly bills of low-income residential electricity customers. Texas's low-income program – the "LITE-UP Texas" program – provides a discount that has ranged from 10 percent to 20 percent[107] on the bills of qualified low-income customers in the competitive areas of ERCOT.[108] The discount must be provided by every REP to qualifying customers, and thus is competitively neutral. REPs are reimbursed for offering this discount from system benefit fund monies collected from all REPs.

Other programs included in the system benefit fund are: a weatherization program offered at no cost to eligible customers to help them lower their electricity (and other energy) bills by making improvements to homes and apartments that save natural gas and electricity; payment assistance funds to assist customers in times of need; customer education about electric competition; and market monitoring.[109,110]

Not all of these programs, including the low-income discount, have been funded in every budget cycle. The low-income discount was available year-round from 2002 through 2005. In response to the Texas 2003 budget crisis, the Legislature allowed the money in the system benefit fund to be used for other programs in 2005, including programs not directly or indirectly related to the provision of electric services in the state.[111] Of the $152 million collected for the fund in 2005, for example, less than half (about $60

[105] Unlike other states, in Texas the System Benefit Charge ("SBC") is not a separate line item on retail electricity customer bills. While it is presumed to be a charge that is passed through to consumers by their REPs, it is not necessarily the case as it is in other states where the electric utility company is in some sense the collection agent for dollars tied to line items on customers' monthly electricity bills.

[106] AECT, "System Benefit Fund: Current Status," February, 2005.

[107] AECT, "System Benefit Fund: Current Status," February, 2005.

[108] PUCT, "Frequently Asked Questions," available at http://www.puc.state.tx.us/ocp/assist/liteup/LiteUp_FAQ_e.pdf.

[109] Texas Rose, "System Benefit Fund Weatherization," available at http://www.texasrose.org/RTF1.cfm?pagename =System %20Benefit%20Fund%20Weatherization.

[110] PUCT, "Customer Facts: Electric Customer Low Income Assistance," available at http://www.puc.state.tx.us /ocp/electric/elecfacts/LOWINCO.pdf.

[111] AECT, "System Benefit Fund: Current Status," February 2005.

million) went to SBF programs.[112] In 2005, the Texas Legislature chose not to appropriate any funds to LITE-UP Texas for the regular budgeting cycle of the 2006-07 biennium.[113] In 2007, the Legislature appropriated funding only to support discounts during the summer months, beginning with July 2007.[114]

Reasons for Texas's Relative Success

From the point of view of assuring that low-income and other programs have been sustained during the transitions to a competitive retail market, Texas has faced some bumps in the road. The system benefit charge, as originally envisioned by Texan legislators, was to be exclusively used to support low-income electric and other public benefit programs. However, support for these programs in Texas has faced some of the same pressures experienced in many other states in recent years where funds collected from electricity customers for various electricity-related purposes (i.e., the system benefit fund) have been used for other public purposes unrelated to electricity as determined to be necessary by state legislatures in times of state budget constraints. That said, Texas has managed to administer its programs in a competitively neutral fashion, from the perspective of holding all retail suppliers to comparable requirements.

Reasons for the Overall Success of Texas's Competitive Electricity Market

The success of the competitive electricity market in Texas can be attributed to a variety of factors that could be replicated by other states that may be considering changes in the features of their own competitive electric markets.

Factors That Could Be Replicated In Other States or Regions

1. **Customer Focus**: Texas designed its power market with the customer as its focal point. Customers have been the target of information campaigns, of systems to ease switching and the provision of service, of relationships with competitive suppliers (rather than with the utility or the generator). Customer choice is considered both a right and a responsibility, in ways more akin to the expectations of customers in other types of markets than in traditional electric service arrangements provided by monopoly utility companies. In Texas, the customer relationship is a key element of the competitive market, and the relationship lies with the retail supplier, not the utility.

2. **Design of Retail Default Service:** Texas designed its five-year transition in a way that assisted the state and its electricity customers in actually moving to full

[112] AECT, "System Benefit Fund: Current Status," January 2007.

[113] PUCT, "Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas," January 2007, p. 47.

[114] PUCT, "Frequently Asked Questions," available at http://www.puc.state.tx.us/ocp/assist/liteup/LiteUp_FAQ_e.pdf.

competition, rather than temporarily shielding customers from price signals reflecting the realities of today's energy market conditions. The transition allowed for periodic price adjustments to the PTB when underlying fuel and purchased power prices changed. These facts allowed a robust retail electricity market to develop and served to *transition* consumers to a new industry model rather than simply buffer them from price fluctuations in underlying electricity markets. Ironically, one of the measures that many other states adopted as a way to assure that customers received some benefits from competition – that is, the reliance on long-term rate caps – ended up serving in some states to undermine the very development of competitive retail electricity markets, along with the innovations and other benefits that they might produce for customers in the long run.

3. **Uniform Business Rules and Codes of Conduct:** Entry barriers for prospective REPs were lowered as a result of the policy to have uniform business rules and to centralize the electricity service registration functions at ERCOT. The "Code of Conduct for Electric Utilities and Their Affiliates," established in 1999, was important to ensure that competitive market participants (i.e., retail electricity providers and power generation companies) received non-discriminatory treatment by transmission/distribution utility companies. In addition, PURA 39.157 provides the PUCT the authority to monitor market power associated with the generation, transmission, distribution, and sale of electricity in Texas and the ability to require mitigation of market power following a finding that market power abuses or other violations are occurring.

4. **Customer Education**: Texas's and REP's aggressive customer education and outreach programs have supported a relatively informed base of retail electricity customers, with nearly universal awareness among "electricity decision makers" of their rights and responsibility to choose their supplier of electric service.

5. **Transmission Expansion Policies**: Texas supported generation investment through its transmission access and cost-allocation policies. In ERCOT's approach, new generation pays for only the direct costs of interconnecting with the transmission network, rather than for more remote transmission system enhancements needed to upgrade the network to accommodate moving power from the resource to demand centers.[115] These other costs are broadly socialized among all users. Such a policy has trade-offs, but served to broaden the geographic footprint of the markets, create incentives for generating capacity additions (including remote wind resources distant from loads) during the early years of the market, and provide customers' access to remote generation resources.

6. **Initial Market Power Mitigation Policies**: Texas supported the start of the wholesale and retail markets through its initial policy of requiring traditional utilities to sell entitlements to at least 15 percent of the power from their installed capacity in

[115] Ross Baldick and Hui Niu, "Lessons Learned: The Texas Experience," University of Texas at Austin, undated, p. 39.

ERCOT. These auctions promoted competition by increasing the amount of generating capacity available to competitive REPs.

7. **Strong Policies for Environmental Improvement**: As part of its restructuring legislation, Texas ensured that emissions from electric generating sources would be reduced through policies that addressed generating resources with air emissions such as fossil fuel power plants that emitted air pollutants (e.g., SO_2, NOx and CO_2). Texas has also excelled in developing wind turbine capacity, not just because of the large wind resource in the state, but because the state's transmission policies lowered barriers to new wind generation and the state's integrated market design provided fertile ground for new wind generation.

8. **Strong Alignment of Retail and Wholesale Market Design and Policies**: The Texas electricity wholesale and retail markets were designed at the onset as a unified whole to support the development of efficient markets in each. The state's initiatives enabled the market to develop many important "prerequisite" conditions for a market to operate efficiently, including through structural changes; unbundling of the utilities into a PGC, a TDU, and a REP; mandatory auctioning of incumbent utilities' entitlements to capacity for initial periods of the transition; grid operations and certain market-administration functions (e.g., energy balancing, ancillary services, switching registration functions) carried out by the ISO (ERCOT); market monitoring functions carried out under the oversight of the PUCT and with the assistance of a third-party market monitor; establishment of a series of policies to support informed consumers; a bilateral contracting environment among willing buyers and willing sellers; and creation of an environment in which retail customers were the focus of core relationships in the competitive marketplace. Additionally, long-standing policies to support relatively short permitting periods and strong investment in transmission infrastructure facilitated the entry of generation and transmission capacity. Together, these allowed for the conditions necessary for an efficient electricity market.

9. **Stable Regulatory Environment**: Finally, a decade of relatively stable and transparent market rules has helped to send favorable signals to the investment community about prospects in the Texas market. These market rules include tools for the REP to manage bad debt risk including the ability to disconnect for non-payment of electric service.

On the Texas Agenda: Continuing Improvements and Challenges

Several elements of the Texas power market have been identified by policymakers and various market participants as needing to further refinement in the future, in order for Texas's market to continue to improve. These include:

Congestion and a Nodal Wholesale Market: ERCOT has found that management of local (intra-zonal) and inter-zonal transmission congestion remains challenging,[116] and decided in 2006 to move from a zonal market system to a nodal design starting in 2009. The new nodal energy market will include a two-settlement market (day-ahead and real-time) based on central dispatch and locational marginal prices. This will be a clearing-price market for each of the settlement periods, with a single price at each of the nodes. The real time market will replace the current balancing energy market. A new day-ahead market will provide price and quantity commitments, and is expected to add price certainty and to attract more generators bids because their owners will be better able to calculate whether or not they will recover their startup and ramping costs.[117] Supporters of the new design indicate that it will provide improved price signals in different locations on the grid, improved dispatch efficiencies producing a lower overall cost of power supply and more efficient management of congestion, and direct assignment of local congestion costs.[118] This change in market design will render ERCOT closer in design to some of the "organized" markets in other regions of the U.S., including PJM, New York, and New England.[119] Under the revised design, ERCOT will continue with its energy-only market.

The increased zonal congestion occurring in 2008 has put a significant strain on the capabilities of the ERCOT market and exposed some of the weaknesses in its structure for pricing transmission congestion. The events of May-June 2008 clearly demonstrate the need for a nodal market, as well as the need to improve both the market design for the pricing of and the operational management of inter-zonal congestion. (The nodal market successfully ran a 29 minute test at the end of June, but has experienced setbacks in the launch date due to late software deliveries. The market, originally set to open December 1, 2008, has now been pushed back to an undetermined date.[120])

Figures 21 and 22 demonstrate the difference in pricing under the zonal and nodal models for a particular constraint in ERCOT. These figures simulate the differences in prices

[116] In early June 2008, ERCOT voted on an emergency basis to "give its staff more flexibility in picking power plants for dispatch into balancing energy markets to relieve severe local congestion, which has been seen as a major reason for the recent swings in electric power prices in Texas....The new market rule also lets ERCOT staff apply more precise, localized congestion management techniques, rather than working to manage congestion zone by zone...Zonal congestion management is 'inherently inefficient...even when it has been effective,' said ERCOT Independent Market Monitor Dan Jones, a consultant with Potomac Economics." Jeff Beattie, "ERCOT Scrambles To Ease Soaring Texas Grid Prices," The Energy Daily, June 10, 2008.

[117] Robert J. Michaels, "Competition in Texas Electric Markets: What Texas Did Right & What's Left to Do," Texas Public Policy Foundation, March 2007, p. 21.

[118] See, for example, Potomac Economics (ERCOT Independent Market Monitor), "2006 State of the Market Report for the ERCOT Wholesale Electricity Markets," August 2007, pp. iv-v.

[119] See, for example, Susan F. Tierney, Todd Schatzki and Rana Mukerji, "Pay-As-Bid versus Uniform Pricing: Discriminatory Auctions Promote Strategic Bidding and Market Manipulation," *Public Utilities Fortnightly*, March 2008.

[120] "ERCOT Runs Nodal Market Test 29 Minutes Without a Hitch," *Restructuring Today*, June 30, 2008; ERCOT, "EROCT Announces Delay in Nodal Market Launch Date," May 20, 2008, available at http://www.ercot.com/news/press_releases/2008/nr05-20-08.

that would arise under congestion conditions for different subareas of ERCOT under the two pricing models.

Figure 21

N-S Constraint Zonal Simulation[121]

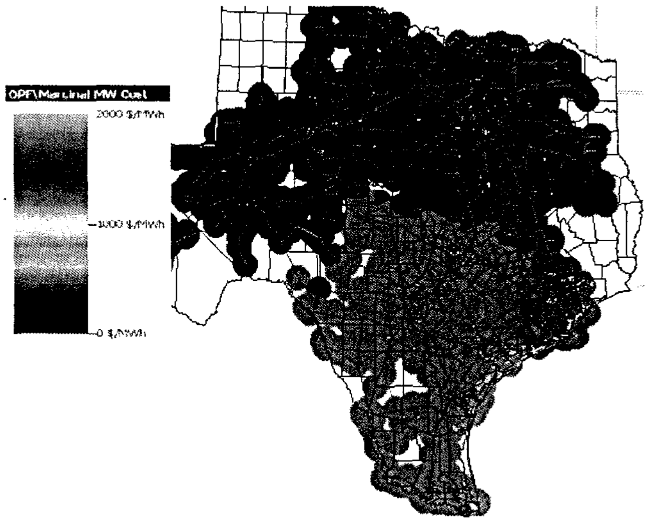
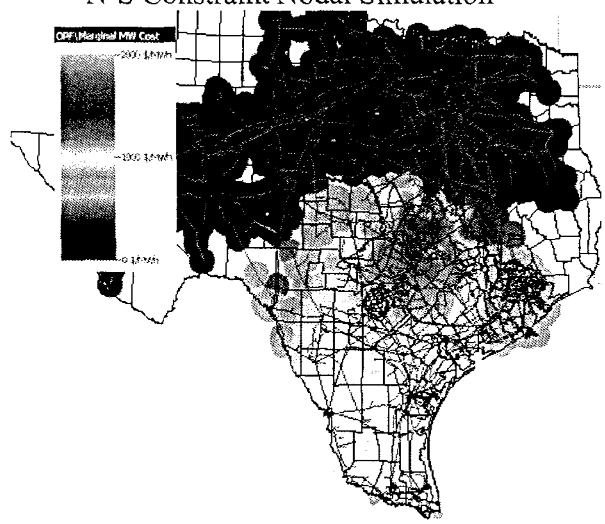


Figure 22

N-S Constraint Nodal Simulation[122]



As can be seen, under the zonal market, prices are much higher (magenta and red colors, as shown in the southern half of ERCOT in Figure 21) over a much broader area than

[121] Dan Jones, Potomac Economics, ERCOT's Independent Market Monitor, "ERCOT Wholesale Market," Presentation before the Texas House Regulated Industries Committee on June 23, 2008.

[122] Dan Jones, Potomac Economics, ERCOT's Independent Market Monitor, "ERCOT Wholesale Market," Presentation before the Texas House Regulated Industries Committee on June 23, 2008.

under a nodal design (where these high prices appear in a relatively limited area in central ERCOT on Figure 22). This is because the current zonal market treats all generation as having the same impact on a constraint, and therefore deserving of being paid the same price to relieve the constraint. In fact this is unlikely to be true in most places during congestion conditions, as the nodal design demonstrates. Beyond this pricing design flaw, the assumption that all generation in a zone has the same impact on a constraint also leads to inefficient and thus more expensive deployment of generation to relieve a constraint. As a result, the cost to consumers has been very high recently. ERCOT should consider ways to address this pricing design flaw pending the move to a nodal design.

Continued Monitoring and Mitigation of Concentration of Generation Ownership: After the initial period in the transition to competitive markets during which generating companies were required to divest entitlements in generating capacity so as to limit their control over generation resources in ERCOT, concerns have been raised more recently about market power in ERCOT's wholesale markets. Two generating companies – TXU and NRG Energy – own a substantial share of generating resources in the market. As noted previously, the PUCT has authority to monitor and, if appropriate, mitigate market power in ERCOT and does so through the thorough assistance of an Independent Market Monitor ("IMM"), a position held by Potomac Economics.

After investigating conditions in certain aspects of ERCOT's during portions of the summer of 2005, the PUCT's IMM found that one generating company, TXU, had acted in ways that constituted an abuse of market power in the balancing energy market during that period.[123] The PUCT Staff subsequently issued a notice of violation and proposed a substantial financial penalty[124] on TXU. An outcome from this proceeding is still awaiting action at the PUCT.

More recently, the PUCT's IMM has found that overall, "the competitive performance of the market improved in 2006" and noted a number of ways in which the changes underway in ERCOT's markets (including the implementation of a nodal market design

[123] The IMM's report found that "TXU had the ability to substantially increase balancing energy prices. TXU's ability to raise prices is highest when it is "pivotal", i.e., its balancing energy offers are necessary to satisfy the balancing energy demand. Given the frequency with which TXU is pivotal, and the historical information available to TXU on offer patterns and deployments in the balancing energy market, TXU could foresee that economically withholding significant quantities would be likely to result in higher balancing market prices. TXU was a substantial net seller in the balancing energy market during the Study Period, which provided it the incentive to raise prices. The offers that TXU submitted under its RBS strategy were not competitive and contributed to a significant increase in balancing energy prices during the Study Period. This increase in prices was inefficient and did not reflect underlying market fundamentals .... Based upon these results, we conclude that TXU's actions constituted an abuse of market power in the balancing energy market during the Study Period." Potomac Economics (ERCOT Independent Market Monitor), "Investigation of the Wholesale Market Activities of TXU from June 1 to September 30, 2005," March 2007, p. 4.

[124] The initial penalty of $210 million was later revised to $171 million after recalculation by the PUCT. Jaime Jordan, "PUC Staff Recommends Reduced TXU Penalty," *Dallas Business Journal*, September 18, 2007, available at http://www.bizjournals.com/dallas/stories/2007/09/17/daily13.html?ana=from_rss.

in 2009 and a stronger demand side of the market) will continue to enhance the competitive performance of the Texas wholesale market.[125]

A Stronger Demand Side of the Market: One of the notable themes in recent discussions of wholesale power market design and performance around the U.S. is the need to assure a strong demand-side element in the market.[126] Other wholesale power markets are endeavoring to install infrastructure to provide at least a segment of the customer base with advanced metering capability so that customers (or their agents, acting on their behalf) can "see" real-time prices and then manage portions of their energy use in response to those price signals. Such price-responsive demand can improve the efficiency of power production and mitigate the potential exercise of market power among generators. Doing so, however, requires investment in infrastructure. Market participants and the PUCT are currently working toward rolling out advanced meter infrastructure and associated products.[127]

Further Price Transparency and Liquidity in Wholesale Markets: While Texas has a relatively high degree of price information in retail markets, it offers less transparency in wholesale prices and less liquidity in the day ahead and real-time markets than in some of the organized markets in other regions of the U.S. When ERCOT develops its two-settlement energy market, a greater degree of information about wholesale market prices and greater liquidity will exist, as compared to today.

Continued Improvements in Transmission Planning and Grid Operations: One of the major initiatives on the agenda of the PUCT is planning and designing support for transmission investments needed to bring power from "Competitive Renewable Energy Zones" ("CREZ") for delivery in other parts of the state. Right now, potentially large amounts of renewable energy resources are bottled up in West Texas, but new generation can be built much faster than new transmission. At least through 2006, the McCamey area of West Texas has had more wind generation added than there was transmission capability to export the power.[128] ERCOT faces a technical challenge of managing greater amounts of wind generation. Quite recently, in mid-July 2008, the PUCT approved a 18,456 MW wind-resource scenario as part of the regulatory effort to endorse a transmission plan tied to deliver power generated from the "most productive wind" zones to various populated areas in the state.[129]

[125] See Potomac Economics (ERCOT Independent Market Monitor), "2006 State of the Market Report for the ERCOT Wholesale Electricity Markets," August 2007, generally and p. xxxi.

[126] See for example, FERC Staff Report, "Assessment of Demand Response and Advanced Metering," September 2007, http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf; and FERC Staff Report, "Assessment of Demand Response & Advanced Metering," *Docket AD-06-2-000*, August 2006, p. 7.

[127] See, PUCT Project #34610 (Implementation Project Relating to Advanced Metering) available at http://www.puc.state.tx.us/electric/projects/34610/34610.cfm.

[128] Ross Baldick and Hui Niu, "Recent History of Electricity Market Restructuring in Texas," University of Texas at Austin, presentation dated August 30, 2006.

[129] Senate Bill 20 (2005) had directed the PUCT to select the most productive wind zones in the state and devise a transmission plan to move power generated from these zones to various populated areas in the state. Pursuant to this directive, the PUCT had asked ERCOT to provide several transmission and wind scenarios to the PUCT. The four scenarios contained a total of 12,053, 18,456, 24,859, and 24,419 MW of installed wind generation distributed among

Conclusion

Following the end of Texas's transition period to a fully competitive market at the beginning of 2007, the performance of the state's electricity market has been of interest to a wide variety of stakeholders. After examining the performance of Texas's electricity market from both a qualitative and quantitative perspective, it is evident that Texas has had an overall successful competitive power market experience.

Texas has met the various qualitative and quantitative criteria for strong competitive market performance and conditions. In contrast to the performance of other states that restructured their electricity markets, Texas's retail and wholesale markets show strong evidence of many of the basic features of competitive markets: the presence of many buyers and sellers; low barriers to entry (including price levels that support (over time) new investment); non-discriminatory access of market participants to essential facilities (such as the wires) and other services necessary to participate in markets; means to monitor the performance of markets and mitigate the ability of market participants to exercise market power; informed consumers; and transparent and relatively stable market rules.

The success of the competitive electricity market in Texas can be attributed to a variety of factors. These are:

1. **Customer Focus**: Texas designed its power market with the customer as its focal point. Customers have been the target of information campaigns, of systems to ease switching and the provision of service, of relationships with competitive suppliers. Customer choice is considered both a right and a responsibility. In Texas, the customer relationship is a key element of the competitive market, and the relationship lies with the retail supplier, not the utility.

2. **Design of Retail Default Service:** Texas designed its five-year transition in a way that assisted the state and its electricity customers in actually moving to full competition, rather than temporarily shielding customers from price signals reflecting the realities of today's energy market conditions. The transition allowed for periodic price adjustments to the PTB when underlying fuel and purchased power prices changed. These facts allowed a robust retail electricity market to develop and served to *transition* consumers to a new industry model rather than simply buffer them from price fluctuations in underlying electricity markets.

3. **Uniform Business Rules and Codes of Conduct:** Entry barriers for prospective REPs were lowered as a result of the policy to have uniform business rules and to centralize the electricity service registration functions at ERCOT. The PUCT has the

five Competitive Renewable Energy Zones ("CREZs") in West Texas and the Texas Panhandle. "This morning the Public Utility Commission of Texas (PUC) selected a transmission scenario that will eventually transmit a total of 18,456 megawatts of wind power from West Texas and the Panhandle to metropolitan areas of the state. The PUC selected scenario 2, which is estimated to cost $4.93 billion, or approximately $4.00 per month per residential customer once construction is complete and costs are reflected in rates. It is expected that the new lines will be in service within four to five years." PUCT Press Release, "Texas Public Utility Commission Approves Wind Transmission Plan," July 17, 2008 available at http://www.puc.state.tx.us/nrelease/2008/071708.pdf.

authority to monitor and mitigate market power associated with the generation, transmission, distribution, and sale of electricity.

4. **Customer Education**: Texas's and REP's aggressive customer education and outreach programs have supported a relatively informed base of retail electricity customers, with nearly universal awareness among "electricity decision makers" of their rights and responsibility to choose their supplier of electric service.

5. **Transmission Expansion Policies**: Texas supported generation investment through its transmission access and cost-allocation policies. In ERCOT, new generators pay for the direct costs of interconnecting with the transmission network, but not the more remote transmission system enhancements needed to upgrade the network. These other costs are broadly socialized among all users. These policies have served to broaden the geographic footprint of the markets, create incentives for generating capacity additions (including remote wind resources), and provide customers access to remote generation resources.

6. **Initial Market Power Mitigation Policies**: Texas supported the start of the wholesale and retail markets through its initial policy of requiring traditional utilities to sell entitlements to at least 15 percent of the power from their installed capacity in ERCOT. .

7. **Strong Policies for Environmental Improvement**: As part of its restructuring legislation, Texas ensured that emissions from electric generating sources would be reduced through policies that addressed generating resources with air emissions such as fossil fuel power plants that emitted air pollutants (e.g., SO_2, NOx and CO_2). Texas has also excelled in developing its wind resource, in part as a result the state's overall siting, permitting, and transmission policies.

8. **Strong Alignment of Retail and Wholesale Market Design and Policies**: The Texas electricity wholesale and retail markets were designed at the onset as a unified whole to support the development of efficient markets in each. The state's initiatives enabled the market to develop many important "prerequisite" conditions for a market to operate efficiently, including through structural changes; unbundling of the utilities into separate entities with different functions; mandatory auctioning of incumbent utilities' entitlements to capacity for initial periods of the transition; grid operations and certain market-administration functions carried out by ERCOT; market monitoring functions carried out under the oversight of the PUCT; establishment of a series of policies to support informed consumers; a bilateral contracting environment among willing buyers and willing sellers; and creation of an environment in which retail customers were the focus of core relationships in the competitive marketplace.

9. **Stable Regulatory Environment**: Finally, a decade of relatively stable and transparent market rules has helped to send favorable signals to the investment community about prospects in the Texas market.

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Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency

by Kira R. Fabrizio, Nancy L. Rose and Catherine D. Wolfram*

Abstract

While neoclassical models assume static cost-minimization by firms, agency models suggest that firms may not minimize costs in less-competitive or regulated environments. We test this using a transition from cost-of-service regulation to market-oriented environments for many U.S. electric generating plants. Our estimates of input demand suggest that publicly-owned plants, whose owners were largely insulated from these reforms, experienced the smallest efficiency gains, while investor-owned plants in states that restructured their wholesale electricity markets improved the most. The results suggest modest medium-term efficiency benefits from replacing regulated monopoly with a market-based industry structure.

Keywords: Competition; Efficiency; Restructuring; Regulation; Deregulation; Electric Utilities.
JEL Codes: JEL L51, L11, L94, L22.

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Economists have long maintained that markets generate important efficiency benefits for an economy. These arguments usually focus on allocative efficiency; the implications of competition for technical efficiency are less clear. Neoclassical models of profit-maximization assume static cost-minimizing behavior by all firms, regardless of market competitiveness.[1] Agency models, however, in recognizing the interplay of asymmetric information with the separation of management and control, suggest possible deviations from cost-minimization by effort-averse managers. These distortions may be amplified when a firm's prices are set by asymmetrically-informed regulators (e.g., Jean-Jacques Laffont and Jean Tirole, 1993). Replacing regulated price determination with markets makes firms residual claimants to cost-savings, potentially increasing incentives for efficiency-enhancing effort.[2] Theory suggests several possible roles for markets: constraining managerial behavior by rewarding efficiency gains, confronting less-efficient firms with the choice of cost reduction to the level of their lower-cost counterparts or exit, and perhaps reducing agency costs.[3] The actual relevance of markets for technical efficiency ultimately is an empirical question.

This paper uses data on the U.S. electric generation sector to assess the effect on technical efficiency of shifting regulated monopolies to more market-based environments. The past decade has witnessed a dramatic transformation of this industry. Until the mid-1990s, over ninety percent of the electricity in the US was sold by vertically-integrated

[1] The implication of competition for dynamic efficiency through innovation is the subject of an extensive theoretical and empirical literature in economics, dating at least from Joseph Schumpeter's 1942 classic *Capitalism, Socialism, and Democracy.*

[2] In contrast, Xavier Vives (2006) develops a model in which deregulation may lead to increased competitive pressure and reduced R&D investment, leading to a negative effect on cost-reducing innovation.

investor-owned utilities (IOUs), most operating as regulated monopolists within their service areas. Many utilities faced some form of incentive-based regulation, adopted by states during the 1980s and early 1990s to improve upon the efficiency incentives of traditional cost-of-service regulation. More radical reform was initiated in the mid-1990s, as many states began to restructure their electric utility markets. Today, nonutility generators own roughly a quarter of generation capacity nationwide, and IOUs in many states own only a small fraction of total generating capacity and operate in a structure that relies heavily on market-based incentives. While studies of state-level electricity restructuring suggest that politicians may have been motivated in large part by rent-seeking (e.g., Matthew W. White, 1996, and Paul L. Joskow, 1997), many proponents of restructuring argued that exposing utilities to competitive, market-based outcomes would yield efficiency gains that could ultimately reduce electricity costs and retail prices.

The considerable body of empirical research on electricity restructuring within the U.S. and abroad has thus far focused on assessing the performance of competitive wholesale markets, with particular attention to the exercise of market power (e.g., Severin Borenstein, James Bushnell and Frank A. Wolak, 2002 and Joskow and Edward Kahn, 2002, and Wolak, forthcoming). While many of the costs of electricity restructuring have been intensively studied, relatively little effort has been devoted to quantifying any ex post operating efficiency gains of restructuring. Christopher R. Knittel (2002) reports evidence of some electric generating plant efficiency increases associated with the diffusion of incentive regulation.[4] The question of whether further reform—moving from

[3] Stephen J. Nickell (1996) provides a discussion of many of these theoretical arguments. Jen Baggs and Jean-Etienne de Bettignies (forthcoming) develop a model in which competition may reduce costs through both direct effects, such as those described in Nickell (1996), and reductions in agency costs.

[4] Incentive regulations have been more extensively studied in the telecommunications sector; e.g., Chunrong Ai and David Sappington (2002), or Donald Kridel, Sappington, and Dennis Weisman (1996) for a survey of many such studies.

incentive-based regulation to deregulated markets for generation—yields additional improvements in plant efficiency remains open.

Research on other industries suggests productivity gains associated with deregulation (e.g., G. Steven Olley and Ariel Pakes, 1996, on telecommunications and Charles K. Ng and Paul Seabright, 2001, on airlines) and with increased competitive pressure caused by factors other than regulatory change (e.g., José E. Galdón-Sánchez and James A. Schmitz, Jr., 2002, on iron ore mines).[5] This study provides the first substantial analysis of early generation efficiency gains from electricity restructuring.[6] As such, it is of direct policy relevance to states contemplating the future of their electricity restructuring programs, and contributes to the broad economic debate on the role of competition in the economy.

The results of our work indicate that the plant operators most affected by restructuring reduced labor and nonfuel expenses, holding output constant, by three to five percent relative to other investor-owned utility plants, and by six to twelve percent relative to government- and cooperatively-owned plants that were largely insulated from restructuring incentives. These may be interpreted as the medium-run efficiency gains that Joskow (1997, p. 214) posits "may be associated with improving the operating

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[5] Some hint of this possibility in electricity is provided by Walter J. Primeaux (1977), who compared a sample of municipally owned firms facing competition to a matched sample of municipally owned firms in monopoly situations and found a significant decrease in costs per kWh for firms facing competition.

[6] Joskow (1997) describes the significant labor force reductions that accompanied restructuring in the UK, as the industry moved from state-owned monopoly to a privatized, competitive generation market, although these mix restructuring and privatization effects. The only econometric evidence on restructuring of which we are aware is from L. Dean Hiebert (2002), who uses stochastic frontier production functions to estimate generation plant efficiency over 1988-1997, treating all inputs as orthogonal to productivity shocks. Hiebert models plant inefficiency as a function of several variables, including indicators for state regulatory or legislative enactment of utility restructuring in 1996 and in 1997. He reports a huge reduction in estimated mean inefficiency for coal plants in states deemed to have restructured in 1996 but none for gas plants in those states, and no effect on plants of either fuel type for policies enacted in 1997. Our work uses a longer time period, richer characterization of the restructuring environment and dating of reforms consistent with the U.S. Energy Information Administration, and an alternative technology specification that both allows for more complex productivity shocks and treats possible input endogeneity biases.

performance of the existing stock of generating facilities and increasing the productivity of labor operating these facilities." Our work also highlights the importance of treating the simultaneity of input and output choice. Failing to recognize that shocks to input productivity may induce firms to adjust targeted output leads to overstatement of estimated efficiency effects, by nearly a factor of two in some cases. While endogeneity concerns have been long recognized in the productivity literature, ours is one of the first studies of electric generation to control for this. Finally, we explore the sensitivity of the estimated efficiency impact to the choice of control group to which restructured plants are compared, and discuss the issues involved in determining the appropriate counterfactual.

The remainder of the paper is organized as follows: Section I describes existing evidence on the competitive effects of efficiency and discusses how restructuring might alter electric generation efficiency. Section II details our empirical methodology for testing these predictions and describes our strategy for identifying restructuring effects. The data are described in Section III. Section IV reports the results of the empirical analysis, and Section V concludes.

I. Why Might Restructuring Affect Generator Efficiency?

Through the early 1990s, the U.S. electricity industry was dominated by vertically integrated investor-owned utilities. Most operated as regulated monopolists over generation, transmission, and distribution of electricity within their localized geographic market, though there was some wholesale power traded among utilities or purchased from a small but growing number of nonutility generators. Prices generally were determined by state regulators based on accounting costs of service at the firm level. It has long been argued that traditional cost-of-service regulation does relatively well in limiting rents but less well in providing incentives for cost-minimizing production (e.g., Laffont and Tirole, 1993). Under pure cost-of-service regulation, regulator-approved costs are passed directly through to customers, and reductions in the cost of service yield at most short-term profits until rates are revised to reflect the new lower costs at the next rate case.[7] Given asymmetric information between regulators and firms, inefficient behavior by managers that raises operating costs above minimum cost levels generally would be reflected in increased rates and passed through to customers. Joskow (1974) and Wallace E. Hendricks (1975) demonstrate that frictions in cost-of-service regulation, particularly those arising from regulatory lag (time between price-resetting hearings), may provide some incentives at the margin for cost-reducing effort. Their impact generally is limited, however, apart from periods of rapid nominal cost inflation (Joskow, 1974).

This system led economists to argue that replacing cost-of-service regulation with higher-powered regulatory incentive schemes or increased competition could enhance efficiency.[8] Over the 1980s and early 1990s, many state utility commissions accordingly adopted some form of incentive regulation. The little empirical evidence available on these reforms, which modify price setting within the regulated monopoly structure, suggests limited effects. Knittel (2002) studies a variety of incentive regulations in use through 1996, and finds that those targeted at plant performance or fuel cost were associated with gains in plant-level generation efficiency.[9] More general reforms, such as price caps, rate freezes, and revenue-decoupling programs, typically were associated with insignificant or negative efficiency estimates, all else equal.

[7] Rates are constant between rate cases, apart from specific automatic adjustments (such as fuel adjustment clauses), so changes in cost would not be reflected in rates until the next rate case.
[8] See, for example, Laffont and Tirole (1993), for a theoretical justification, or Joskow and Richard Schmalensee (1987), for an applied argument.
[9] Knittel uses OLS and stochastic production frontier techniques to estimate Cobb-Douglas generating plant production functions in capital, labor, and fuel for a panel of large IOU plants over 1981-1996. His results from first-differenced models, which implicitly allow for fixed plant-level efficiency effects, suggest gains

During the second half of the 1990s, states began to shift their focus from incentive regulation to restructuring. By 1998, every jurisdiction (50 states and the District of Columbia) had initiated formal hearings to consider restructuring their electricity sector, and by 2000, almost half had approved legislation introducing some form of competition that included competitive retail access, whereby companies competed to sell power to retail customers.[10] Restructuring initiatives, in contrast to incentive regulations, fundamentally changed the way plant owners earn revenue. At the wholesale level, plants sell either through newly created spot markets or through long-term contracts that are presumably based on expected spot prices. In the spot markets, plant owners submit bids indicating the prices at which they are willing to supply power from their plants. Dispatch order is set by the bids, and, in most markets, the bid of the marginal plant is paid to all plants that are dispatched. High-cost plants will be forced down in the dispatch order, reducing expected revenue.[11] Plant operators that reduce costs can move higher in the dispatch order to increase dispatch probability, and increase the profit margin between own costs and the expected market price. Most restructuring programs also changed the way retail rates are determined and the way in which retail customers are allocated.[12] Retail access programs in combination with the creation of the new wholesale spot markets may increase the intensity of cost-cutting incentives, leading to even greater effort to improve efficiency.

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on the order of 1-2 percent associated with these reforms. Equations that do not allow for plant fixed effects suggest much larger magnitudes.

[10] In the aftermath of California's electricity crisis in 2000-2001, restructuring has become less popular and many states have delayed or suspended restructuring activity, including six that had previously approved retail access legislation. See US Energy Information Administration (EIA), 2003.

[11] This could induce closure. We address potential selection-induced biases from exit below.

[12] States have used a variety of approaches to link retail rates under restructuring to wholesale prices in the market. Over the short term, most states decoupled utility revenue from costs by mandating retail rate freezes, often at levels discounted from pre-restructuring prices. Some states, such as Pennsylvania, are aggressively trying to encourage entry by competitive energy suppliers, who may contract directly with retail customers.

Exit by less-efficient firms is a well-understood efficiency benefit of competition: as output shifts from (innately) higher-cost firms to lower-cost competitors the total production cost for a given output level declines. Olley and Pakes (1996) provide empirical evidence of this phenomenon in their plant-level analysis of the magnitude and source of productivity gains in the U.S. telecommunications equipment industry over 1974-1987. They find substantial increases in productivity associated with the increased competition that followed the 1984 divestiture and deregulation in this sector, and identify the primary source of these gains as the re-allocation of output from less productive to more productive plants across firms. In a similar vein, Chad Syverson (2004) finds that more competitive local markets in the concrete industry are associated with higher mean, less dispersion, and higher lower-bounds in plant productivity, effects he attributes to the exit of less-efficient plants in more competitive environments.

The existing evidence on whether competition also leads to cost reductions through technical efficiency gains by continuing producers and plants is relatively sparse. Nickell (1996) uses a panel of 670 U.K. manufacturing firms to estimate production functions that include controls for the competitive environments in which firms operate. He finds some evidence of reduced productivity levels associated with market power and strong support for higher productivity growth rates in more competitive environments. Concerns about the ability of cross-industry analysis to control adequately for unobservable heterogeneity across sectors may make sector-specific evidence tighter and more convincing.[13] A notable example is the Galdón-Sánchez and Schmitz (2002) study of labor productivity gains at iron ore mines that faced increased competitive pressure

[13] A number of studies have analyzed efficiency gains following regulatory reform in various industries; see, for example, Elizabeth E. Bailey (1986) and B.U. Park et al. (1998) on airlines. Unfortunately, in many cases it is difficult to disentangle direct regulatory effects on efficiency (e.g., operating restrictions imposed on trucking firms or airlines by regulators in those sectors) from the indirect effects of reduced competition.

following the collapse of world steel production in the early 1980s. They find unprecedented rates of labor productivity gains associated with this increase in competitive pressure, "driven by continuing mines, producing the same products and using the same technology as they had before the 1980s" (at 1233).[14]

Several features of the electric generation sector make it an attractive subject for testing these potential competitive effects on technical efficiency.[15] First, generation technology is reasonably stable and well-understood and data on production inputs and outputs at the plant-level are readily available to researchers. This has made electric generation a common application for new production and cost function estimation techniques, dating at least from Marc Nerlove (1963). Second, policy shifts over a relatively short period have resulted in a dramatic transformation of the market for electric power. This provides both time series and geographic variation in competitive environments. Finally, static and dynamic efficiency claims bolstered much of the policy reform; measuring these benefits is a vital prerequisite to assessing the wisdom of these policies.

While the most significant savings from restructuring are likely to be associated with efficient long-run investments in new capacity, there may be opportunities for modest reductions in operating costs of existing plants (Joskow, 1997). This paper attempts to measure the extent of that possible improvement for the existing stock of electricity generating plants in the U.S. The implicit null hypothesis is that before restructuring, operators were minimizing their costs given the capital stock available in the

[14] Ng and Seabright (2001) estimate cost functions for a panel of U.S. and European airlines over 1982-1995, and conclude that potential gains from further privatization and increased competition among European carriers are substantial, though they point out that the best-measured component of these gains relates to ownership rather than market structure differences.

[15] Understanding possible reallocation of output across plants is hampered by the exit of plants from most publicly available databases when they are sold to nonutility owners.

industry. Under the null, there should be no change in plant-level efficiency measures associated with restructuring activity. We discuss below our method for estimating plant efficiency and identifying deviations from this hypothesis. To assess the effects of restructuring, we need to specify how generating plants would have operated absent the policy change. Constructing this counterfactual is crucial, but difficult.

II. Empirical Model

For a single-output production process, productive efficiency can be assessed by estimating whether a plant is maximizing output given its inputs and whether it is using the best mix of inputs given their relative prices. Production functions describe the technological process of transforming inputs to outputs and ignore the costs of the inputs; a plant is efficient if it is on the production frontier. Cost minimization assumes that, given the input costs, firms choose the mix of inputs that minimizes the costs of producing a given level of output. A plant could be producing the most output possible from a given input combination but not minimizing costs if, for instance, labor were cheap relative to materials, yet the plant used a lot of materials relative to labor. Even if the plant were producing the maximum output possible from its workers and materials, it would not be efficient if it could produce the same level of output less expensively by substituting labor for materials. We explore the impact of restructuring on efficiency by specifying a production function and then deriving the relevant input demand equations implied by cost minimization.

We adopt the convention of representing electric generating plant output (Q) by the net energy the generating units produce over some period. This is measured by annual megawatt-hours, MWh, in our data, as discussed in further detail in the data section below. While many studies of generating plant productivity model this output as a function of current inputs using a Cobb-Douglas production function, the characteristics of electricity production argue strongly for an alternative specification. We derive a model of production and cost minimization that is sensitive to important institutional characteristics of electricity production that have been ignored in much of the earlier literature.

First, observed output in general will be the lesser of the output the plant is prepared to produce given its available inputs (we call this probable output), and the output called for by the system dispatcher (we call this actual output). Because the system dispatcher must balance total production with demand at each moment, the gap between probable (Q^P) and actual (Q^A) output for a given plant *i* will be a function of demand realizations, the set of other plants available for dispatch, and plant *i*'s position in the dispatch order.[16]

Second, while fuel inputs are varied in response to real-time dispatching and operational changes, other inputs to a plant's production are determined in advance of output realizations. Capital typically is chosen at the time of a unit's construction (or retirement), and at the plant level large capital changes are relatively infrequent. From the manager's perspective, it may be considered a fixed input. Utilities hire labor and set operating and materials expenditures in advance, based on expected demand. While these can be adjusted over the medium-run, staffing decisions as well as most maintenance expenditures are not tied to short-run fluctuations in output.[17] We therefore treat these as set in advance of actual production, and determining a target level of probable output, Q^P.

[16] Random shocks to a plant's operations, such as unexpected equipment failures or equipment that lasts longer than expected, will cause it to produce less or more than its probable output from a set of available inputs.

[17] In fact, over a short time period, maintenance and repair expenditures will be inversely related to output since the boiler needs to be cool and the plant offline for most major work. We deal with this potential simultaneity bias below.

Finally, while labor, materials, and capital may be to some extent substitutable to produce probable output, the generation process generally does not allow these inputs to substitute for fuel in the short-run. Given this description of the technology, we posit a Leontief production process for plant *i* in year *t* of the following form:

(1) $$Q_{it}^{A} = \min[\, g(E_{it}, \Gamma^{E}, \varepsilon_{it}^{E}),\ Q_{it}^{P}(K_i, L_{it}, M_{it}, \Gamma^{P}, \varepsilon_{it}^{P})\cdot \exp(\varepsilon_{it}^{A})]$$

where Q^A is actual output and Q^P is probable output; inputs are denoted by E for energy (fuel) input, K for capital, L for labor, and M for materials; Γ denotes parameter vectors, and ε denotes unobserved (to the econometrician) mean zero shocks. See Johannes Van Biesebroeck (2003) for the derivation of a similar production function he uses to model automobile assembly plant production.

As noted above, fuel input decisions are made in real time, after the manager has observed any shocks associated with the plant's probable output productivity, ε_{it}^{P}, the actual operation of the plant, ε_{it}^{A}, and the plant's energy-specific productivity in the current period, ε_{it}^{E}. Probable output, Q^P, is in contrast determined by input decisions made in advance of actual production. We assume that capital, measured by the nameplate generating capacity of the plant, is fixed.[18] Labor and materials decisions are made in advance of production, but after the level and productivity of the plant's capital is observed. This reflects the quasi-fixity of these inputs over time: staffing decisions and maintenance plans are designed to ensure that the plant is available when it is dispatched, based on the targeted output Q^P. The error term ε_{it}^{P} incorporates productivity shocks that we assume are known to the plant manager in advance of scheduling labor and materials inputs, but are not observable to the econometrician. We allow actual output to differ from probable output by a multiplicative shock $\exp(\varepsilon_{it}^{A})$, assumed to be observed at the time fuel input choices are made but not known at the time probable output is determined. This shock would be, for example, negative if a generating unit were unexpectedly shut down due to a mechanical failure, or positive if the plant were run more intensively than anticipated, as might be the case if a number of plants ahead of it in the usual dispatch order were unavailable or demand realizations were unexpectedly high.

We model probable output (Q^P) as a Cobb-Douglas function of labor and materials, embedding capital effects in a constant ($Q_0(K)$) term. This yields the specification:

(2) $$Q_{it}^P \leq Q_0(K_i)\cdot(L_{it})^{\gamma L}\cdot(M_{it})^{\gamma M}\cdot \exp(\varepsilon_{it}^P)$$

In preliminary analysis, we estimated the parameters of the production function, including terms that allowed for differential productivity under restructuring. Those results suggested productivity gains associated with restructuring. The work reported here imposes an additional constraint, based on cost-minimization, to estimate input demand functions, and isolate possible restructuring effects on each measured input. A cost-minimizing plant manager, facing wages W_{it} and material prices S_{it}, would solve for the optimal inputs to produce probable output $\underline{Q}_{it}^P$ by:

(3) $$\min_{L_{it},\, M_{it}} \quad W_{it}\cdot L_{it} + S_{it}\cdot M_{it} \qquad \text{s.t. } \underline{Q}_{it}^P \leq Q_0(K_i)\cdot(L_{it})^{\gamma L}\cdot(M_{it})^{\gamma M}\cdot\exp(\varepsilon_{it}^P)$$

yielding the following factor demand equations:

(4) $$L_{it} = (\lambda\gamma^L Q_{it}^P)/W_{it}$$

(5) $$M_{it} = (\lambda\gamma^M Q_{it}^P)/S_{it}$$

where λ is the Lagrangian on the production constraint.

[18] The empirical analysis defines a new plant-epoch, *i*, whenever there are significant changes in capacity, so that within each plant-epoch, capacity is approximately constant.

We observe actual output, $Q_{it}^A = Q_{it}^P \exp(\varepsilon_{it}^A)$, rather than probable output, Q_{it}^P. Making this substitution and taking logs of both sides, equation (2) becomes:

(6) $\ln(L_{it}) = \alpha_0 + \ln(Q_{it}^A) - \varepsilon_{it}^A - \ln(W_{it})$

where $\alpha_0 = \ln(\lambda\gamma^L)$. If there are differences across plants, over time, or across regulatory regimes in the coefficients of the production function (γ^L) or in the shadow value of the probable output constraint (λ), or if there is measurement error in labor used at the plant, this equation will hold with error. As we are particularly interested in changes in input demand associated with restructuring, we expand the subscript *it* to *irt* to include plant *i* in year *t*, and regulatory restructuring regime *r*, and re-write equation (6) as: [19]

(7) $\ln(L_{irt}) = \ln(Q_{irt}^A) - \ln(W_{irt}) + \alpha_i^L + \delta_t^L + \varphi_r^L - \varepsilon_{irt}^A + \varepsilon_{irt}^L$

where α_i^L measures a plant-specific component of labor demand, δ_t^L captures year-specific differences in labor demand, φ_r^L captures restructuring-specific shifts in labor demand, and ε_{irt}^L measures the remaining error in the labor input equation. α_0 is now subsumed in the plant-specific demand, α_i^L. Note that φ_r^L picks up mean residual changes in labor input for a plant in a restructured regime relative to that plant overall and to all other plants at the same point in time. It could reflect systematic changes in the marginal productivity of labor (γ^L), in the shadow value of the availability constraint (λ) or in optimization errors. [20]

Similarly, equation (5) becomes:

(8) $\ln(M_{irt}) = \ln(Q_{rt}^A) - \ln(S_{rt}) + \alpha_i^M + \delta_t^M + \varphi_r^M - \varepsilon_{irt}^A + \varepsilon_{irt}^M$

which is directly analogous to equation (7).

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[19] Note that many plant-level differences, such as capital stock, and many time-varying shocks, such as technology-neutral productivity shocks, drop out of this equation when we condition on output choice.

[20] If there are systematic differences in the relation of probable and actual output across restructuring, γ_r^L may also reflect the change in mean ε_{irt}^A. Since ε_{irt}^A reflects shocks unobservable by the firm when setting planned output, it seems plausible that these could be mean zero in expectation, but their realizations could be nonzero in the restructuring sample we observe.

We model the energy component of the Leontief production function, which will in general hold with equality, as:

(9) $$Q_{irt}^{A} = g(E_{irt}, \gamma^{E}, \varepsilon^{E})$$

Assuming that g(•) is monotonically increasing in E, we can simply invert it to get an expression for E in terms of Q. Note that the price of fuel does not enter into the demand for fuel except through the level of output the plant is dispatched to produce. For consistency with the other input specifications, we specify a log-log relationship:

(10) $$\ln(E_{irt}) = \gamma_{Q}^{E} \cdot \ln(Q_{irt}) + \varphi_{r}^{E} + \alpha_{i}^{E} + \delta_{t}^{E} + \varepsilon_{irt}^{E}$$

where as before, the plant-specific error, α_i^E, the year-specific error, δ_t^E, and the restructuring-specific term, φ_r^E, capture systematic changes in the efficiency with which plants convert energy to electricity—that is, changes in plant heat rates—across plants, over time, or correlated with restructuring activity, respectively.

We confront two important endogeneity concerns in estimating the basic input demand equations, (7), (8) and (10). The first is the possibility that shocks (ε_{irt}^{L}, ε_{irt}^{M}, ε_{irt}^{E}) in the input demand equations may be correlated with output. If output decisions are made after a plant's manager observes the plant's efficiency, managers may increase planned output in response to positive shocks to an input's productivity, or reduce planned output in response to negative shocks. This behavior would induce a correlation between the error in the input demand equation and observed output. Though one can control directly for plant-specific efficiency differences and for secular productivity shocks in a given year, idiosyncratic shocks remain a source of possible bias. Second, the estimates may be subject to selection bias if exit decisions are driven by unobserved productivity shocks. In this case, negative shocks could lead to plant shutdown, implying that the errors for observations we observe will be drawn from a truncated distribution. Neither of these problems is unique to our setting, and they have been raised in many earlier papers.[21]

Consider first the simultaneity issue. We face a potential simultaneity problem if, for instance, a malfunctioning piece of equipment reduces the plant's fuel efficiency, leading the utility to reduce its operation of that plant and consequently to use less fuel. There may be deviations from predetermined employment and materials budgets caused by unanticipated breakdowns that require increased use of labor and repair expenditures and result in lower output. A variety of methods have been used to address concerns about simultaneity.[22] We choose to use an instrumental variables approach, using a measure of state-level electricity demand as an instrument for plant output. Geographic electric generation markets are likely to be at least as broad as the state-level at the annual frequency of our data. This demand is likely to be highly correlated with the amount of output a plant will be called to provide, but uncorrelated, for instance, with how efficiently an individual plant's feedwater pumps are working. This approach is likely to be particularly effective for the energy equation, given the responsiveness of energy input choices to demand fluctuations in real time, and for identifying exogenous output fluctuations at nonbaseload plants, which are more strongly influenced by marginal swings in demand. It may be less powerful in identifying variation in ex ante labor and maintenance choices, depending in part on the extent to which plant managers anticipate state demand. We have explored the sensitivity of our results to a broad set of alternative

[21] Nerlove (1963) provides an early discussion of simultaneity bias in production functions. Olley and Pakes (1996) propose a structural approach to addressing simultaneity, which is compared to alternatives in Zvi Griliches and Jacques Mairesse (1998). Daniel A. Ackerberg et al. (2005) discuss this issue and compare treatments proposed by Olley and Pakes (1996) and James Levinsohn and Amil Petrin (2003). While many papers have estimated production or cost functions for electric generating plants, from the classic analyses in Nerlove (1963) and Laurits R. Christensen and William H. Greene (1976) to very recent work such as Andrew N. Kleit and Dek Terrell (2001) and Knittel (2002), electricity industry studies typically have not treated either simultaneity or selection problems.

instruments, including interactions of state demand with relative plant efficiency (heatrates), fuel type, and load profile that allow for plant-level variation in the instrument set, weather-related demand drivers (cooling and heating degree days), and lags in plant-level output (similar to Richard Blundell and Stephen Bond, 1998 and 2000).[23] The results reported below are qualitatively robust to these alternatives.

The potential selection issue is more difficult to address. The plants in our sample are more stable than those studied in many other contexts (especially see Olley and Pakes, 1996), suggesting that the selection problem may be somewhat less severe for electric generation. Exit in our sample is relatively rare, apart from exit induced when restructuring-related divestitures remove the plant from the reporting database. Adverse productivity shocks are much more likely to result in reduced run time than in plant retirements for the large generating plants analyzed in this work. To the extent that the divestitures were mandated by restructuring policies, these also should not create selection problems. In all states where plant divestitures were part of the restructuring process except New York, virtually all of the utility-owned fossil-fuel fired plants were divested, suggesting that the extent and incidence of divestitures following restructuring are largely nondiscretionary.[24] To further gauge the significance of potential selection effects, we have compared results for the unbalanced panel we use in the analysis to those for a panel of plants that continue to operate through the end of our sample period, for which potential selection effects are likely to be most severe. With one exception, the results from the

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[22] See the references cited in note 21, supra.
[23] This is discussed in detail in a Technical Appendix to this paper, available on the American Economic Review website and as an appendix to Kira Fabrizio, et al. (hereafter FRW), 2007. The Technical Appendix discusses these and other robustness checks.
[24] See the analysis in James B. Bushnell and Catherine D. Wolfram (2005) and the discussion in FRW (2007) Technical Appendix.

balanced panel are similar to the main results reported in this paper, suggesting there is little to be gained from a more detailed treatment of potential selection biases.[25]

Identification strategy

There is substantial spatial and temporal heterogeneity in the economic environment in which electric utilities have operated. There are thousands of generating plants operated by hundreds of utilities subject to regulation by dozens of political jurisdictions each setting their own legal and institutional environment. Restructuring, however, is not randomly assigned across political jurisdictions—earlier work suggests that it is strongly correlated with higher than average electricity prices in the cross-section.[26] Fortunately, we have panel data on the costs and operations of most electric generating plants from well before any restructuring until the present. This allows us to construct benchmarks that we believe control for most of the potentially confounding variation.

The plant-specific effects, $\{\alpha_i^N\}$, measure the mean use of input N at plant i relative to other plants in the sample. These effects may be associated with differences in plant technology type and vintage, ownership (government v. private utilities), and time-invariant state effects. The year-specific shock, $\{\delta_t^N\}$, measures the efficiency impact of sector-level shifts over time, such as secular technology trends, macroeconomic fluctuations or energy price shocks. Restructuring effects on plant productivity

[25] The exception is the coefficient on an indicator for transition to *RETAIL ACCESS* competition. This coefficient is smaller and statistically indistinguishable from zero in the balanced panel estimation of the *NONFUEL EXPENSE* regression. This could be due to the fact that several of the states that implemented retail access competition within our sample required generating plant divestitures. Divested plants generally are exempt from publicly disclosing the data that we rely on in our analysis, eliminating them from the balanced sample. The negative coefficient on *RETAIL ACCESS* in the full sample could reflect reduced spending on *NONFUEL EXPENSES* by plants that are eventually divested, though there are too few observations on divested plants to conclude this with any certainty.

[26] The significant role of sunk capital costs in regulatory ratemaking means that high prices do not necessarily imply high operating costs for generation facilities within a state, however. See Joskow (1997) for a discussion of the contributors to price variation across states.

correspond to a nonzero $\{\varphi_r^N\}$. Heterogeneity in the timing and outcomes of state-level restructuring activity allow the data to distinguish between temporal shocks and restructuring effects. While all states held hearings on possible restructuring, the earliest was initiated in 1993 and the latest in 1998. There is considerable variation in the outcome of those hearings, as well, with just under half the jurisdictions (23 states and the District of Columbia) enacting restructuring legislation between 1996 and 2000.[27] The remainder considered and rejected, or considered and simply did not act on, such legislation. This variation allows us to use changes in efficiency at plants in states that did not pass restructuring legislation to identify restructuring separately from secular changes in efficiency of generation plants over time.

It is possible that plants in this control group also altered their behavior over the post-1992 period. This could be due to the introduction or intensification of incentive regulation within states that did not enact restructuring, to the expectation of potential restructuring that did not occur, or to spillovers from restructuring movements in other states (e.g. if regulators updated their information about the costs necessary to run plants of a certain type, or multi-state utilities operating under differing regimes improved efficiency of all their plants, not just those in restructuring states). To the extent this occurs, our comparison will understate the magnitude of any efficiency effect of restructuring.

We therefore consider a second control group, consisting of cooperatively-owned and publicly-owned municipal and federal plants, which for convenience we will refer to collectively as municipal or "*MUNI*" plants, although the group is broader than strictly

[27] We collected information on state restructuring legislation from various Energy Information Administration and National Association of Regulatory Utility Commissioners publications and state public utility commission websites. Since 2000, no additional states have enacted restructuring legislation, and several have delayed or suspended restructuring activity in response to the California crisis.

implied by this label. An extensive literature has debated the relative efficiencies of private and public ownership in this sector under traditional regulation, with quite mixed results. We abstract from this by allowing for plant-specific effects that absorb any levels differences in input use across ownership type. Restructuring generally altered the competitive environment only for private investor-owned utilities within a state, leaving those for publicly- and cooperatively-owned utilities unchanged.[28] This suggests that *MUNIs* may provide a second benchmark against which to measure changes in efficiency associated with restructuring. To control for the possible divergence of publicly-owned plant input use in the years preceding the restructuring period, we allow a separate intercept shift for publicly-owned plants after 1987: *MUNI*POST 1987*.[29] We then adopt a parameterization that measures $\{\varphi_r^N\}$ relative to incremental differences at publicly-owned plants during the period that investor-owned utilities are at risk of restructuring, defined as 1993 forward, through inclusion of an indicator for *MUNI*POST 1992.*

Using N to denote input (labor, nonfuel expenses, or fuel), and $PRICE^N$ to denote the relevant input price (none for the fuel equation), we have input use equation (11):

$$(11) \quad \ln(N_{irt}) = \ln(Q_{irt}^A) - \ln(PRICE^N_{irt}) + \gamma_{87} MUNI{*}POST1987_{it} + \gamma_{92} MUNI{*}POST1992_{it} + \alpha_i^N + \delta_t^N + \varphi_r^N - \varepsilon_{irt}^A + \varepsilon_{irt}^N$$

Base differences in input use across each investor-, publicly-, or cooperatively-owned plant are embedded in the plant fixed effects, $\{\alpha_i^N\}$. All plants experience common annual changes in input use measured by the time effects, $\{\delta_t^N\}$; publicly-owned plants may experience a differential mean shift from these effects following 1987.

[28] Arizona and Arkansas, which included government-owned utilities in restructuring programs, are the two exceptions.

[29] In Figures 1 and 2, we report nonparametric time paths for IOU and *MUNI* plant efficiency that suggest some divergence between the groups prior to the beginning of state restructuring. While the designation of 1988-1992 as a transition period before restructuring is somewhat arbitrary, it serves as a conservative

Restructuring effects are measured by the difference-in-differences in two implicit "nontreatment groups" to which investor-owned plants in restructuring regimes may be compared: investor-owned plants in non-restructuring regimes over 1993-1999 (with the IOU restructuring effect measured by φ_r^N), and *MUNI* plants over 1993-1999 (with the IOU restructuring effect measured by $\varphi_r^N - \gamma_{92}$).

III. Data & Summary Statistics

The analysis in this paper is based on annual plant-level data for large fossil-fueled generating plants owned by U.S. electric utilities. Plants are comprised of at least one, but typically several, generating units, which may be added to or retired from service over the several-decade life of a generating plant. While an ideal dataset would allow us to explore efficiency at the generating unit level, inputs other than fuel are not available at the generating unit level. Some inputs, such as employees, are not assignable to a unit as they are shared across units at the plant.[30] We therefore use a plant-year as an observation.

The Federal Energy Regulatory Commission (FERC) collects data for investor-owned utility plants annually in the FERC Form 1, and the EIA and Rural Utilities Service (RUS) collect similar data for municipally-owned plants and rural electric cooperatives, respectively. These data include operating statistics such as size of the plant, fuel usage, percentage ownership held by the operator and other owners, number of employees, capacity factor, operating expense, year built, and many other plant-level statistics. Our base dataset includes all large fossil-fuel steam and combined cycle gas turbine generating

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control for pre-period relative changes and is broadly reflective of policy transitions during the mid-1980s and early 1990s (Joskow, 1997).

[30] Some labor may be shared across multiple plants, though assigned to one particular plant in our data. This will induce measurement error, particularly in our plant employment variable.

plants for which data were reported to FERC, EIA or RUS over the 1981 through 1999 period.[31] Further details on data construction are provided in the data appendix.

We follow the literature in characterizing output by the total energy output of the plant over the year, measured by annual net megawatt-hours of electricity generation, *NET MWH.* This is an imperfect choice. Output is, in reality, multidimensional, although most dimensions are not recorded in the plant data. For example, generating plants may also provide reliability services (such as spinning reserves, when the plant stands ready to increase output at short notice), voltage support and frequency control. While the production process varies considerably across these different outputs, only net generation is well-measured in the data.[32]

More importantly, electricity output is not a homogenous product. The availability of the plant may be an important modifier of output quality. Because electricity is not storable, firms must decide how to balance the costs associated with taking their plant down to do maintenance against the probability that a poorly maintained plant will fail during peak demand hours. Changes in incentives associated with restructuring may have altered firms' assessments of these tradeoffs, although the expected direction of the effects is theoretically ambiguous.[33] Hourly output prices and output from individual plants might allow us to better assess this. Lacking such data, we rely on a single output dimension, while acknowledging its limitations.

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[31] One unfortunate consequence of restructuring is that available data on plants sold by utilities to nonutility generators are extremely limited after the sale, due to changed reporting requirements. This means that plants will be excluded from our dataset after such sales.

[32] The inputs required to produce a given level of energy (MWh) from a specific plant also will depend on whether the plant runs continuously or intermittently and on its average capacity utilization. Starting a plant frequently and running it at low capacity utilization rates typically use more inputs (particularly fuel) per MWh generated than does running a plant continuously at its rated capacity.

[33] For instance, under traditional regulation, utilities may have faced strong political incentives to avoid blackouts or brownouts, leading to investment in greater capacity to increase reserve margins and in greater maintenance resources to increase plant reliability. On the other hand, competitive firms producing in

We have information on three variable inputs. The first, *EMPLOYEES,* is a count of full-time equivalent employees at the plant. The second, *NONFUEL EXPENSE,* includes all nonfuel operations and maintenance expenses, such as those for coolants, repairs, maintenance supervision and engineering. This variable is less than ideal as a measure of materials, both because it reflects expenditures rather than quantities, and because it includes the wage bill for the employees counted in *EMPLOYEES*, although that expense is not separately delineated in our data. As *NONFUEL EXPENSES* includes payroll costs, both this and *EMPLOYEES* will reflect changes in staffing.[34] The third input is the quantity of fuel consumed by type of fuel (tons of coal, barrels of oil, and mcf of natural gas). We convert fuel into *BTU*s using the reported annual plant-specific Btu content of each fuel to obtain total *BTU* input at the plant for each year.

Input prices pose a challenge. We do not observe firm- or plant-level wages. Our basic specifications use the variable *WAGE*, reflecting the Bureau of Labor Statistics state-level average utility wage by ownership type: investor-owned or publicly-owned. For *MUNI* plants in states without a publicly-owned utility wage series, we impute wage to be the product of investor-owned utility wages for that state and the average ratio of publicly- to investor-owned utility wages overall. This variable is problematic: not only does it measure firm-specific wages with error, but it is susceptible to the potential endogeneity of wages to the regulatory environment.[35] We have experimented with

restructured wholesale markets may face even stronger incentives to be available when demand peaks because this is when prices are highest.

[34] The elasticity of *NONFUEL EXPENSES* with respect to *EMPLOYEES* is about .5 in our data, broadly consistent with our back of the envelope calculations suggesting that labor costs are roughly half of the total nonfuel operating budget.

[35] Hendricks (1975) suggests that utilities may bargain less aggressively over input prices such as wages during periods in which higher costs can be readily passed on to customers through higher regulated prices, and more aggressively when the firm is likely to be the residual claimant to cost savings. In other industries, regulatory reform has sometimes been associated with substantial reductions in wages, suggesting rent-sharing under regulation (see Nancy L. Rose, 1987, on the trucking industry). Moreover, electricity workers tend to be highly unionized, and unions may bargain over employment terms as well as wages. These

specifications that instrument for utility wages with the state average wages of workers in comparable labor markets, including natural gas distribution, petroleum refining and hazardous waste treatment facilities. While this instrument may in theory better reflect an exogenous opportunity wage for workers at power plants, the results using this are much noisier (though the non-*WAGE* coefficients are not materially affected). We therefore use *WAGE* in our basic specifications. We do not have reasonable indices for the materials prices that comprise *NONFUEL EXPENSES,* even at the state-industry level. Our empirical model of *NONFUEL EXPENSES* therefore corresponds to an input demand equation with constant real relative prices and a price coefficient of one.

The final input is the capital stock of the plant, which we measure by plant capacity and vintage. Our data record the plant capacity in megawatts. We combine this with information on unit retirements to define plant-epochs. Each plant is assigned a unique identifier. Any time the capacity of the plant is significantly changed, we create a new identifier and associated new plant-epoch specific effect. This allows capital changes to alter the underlying input efficiency of the plant. There may be variation within plant-epoch when "scrubbers" (flue-gas desulfurization systems, or FGDs), are installed to reduce sulfur-dioxide emissions by some coal plants. *SCRUBBERs* affect the environmental output, unmeasured by ln(*NET MWH*), which may suggest less efficient operation conditional only on observed output. We therefore include a direct control for the presence of a *SCRUBBER.*

Operational plant data are supplemented with information on state-level restructuring activity. For each state, we have identified (i) the date at which formal hearings on restructuring began, (ii) the enactment date for legislation restructuring the

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considerations suggest that observed wages may not be exogenous to the firm, and may not reflect the state's utility sector, if any, (iii) the implementation date for retail access under that legislation, and (iv) associated aspects of restructuring such as rate freezes and mandatory divestiture of generation. Testing for restructuring-specific shocks requires a determination of how to match this information with firm decisions: when were plant operators in a given state likely to have begun responding to a policy change? Consultations with industry participants and readings of these events suggest that utilities often acted in advance of final legislative or regulatory outcomes. The process leading to state restructuring typically lasted a number of years, allowing utilities to anticipate the coming change, and alter their behavior in advance. For example, Boston Edison's 10-K filed in March 1994 discussed Massachusetts' consideration of restructuring, stating "The Company is responding to the current and anticipated competitive pressure with a commitment to cost control and increased operating efficiency without sacrificing quality of service or profitability" (Boston Edison, 1994, p. 6).[36] Massachusetts had just begun holding formal hearings on restructuring the industry in 1994. Utilities may have phased input changes, especially those involving labor and particularly unionized workers. Moreover, as policy changes were discussed, rates were frozen in many states, either explicitly by policy makers or in effect by implicit PUC decisions not to hear new rate cases, enabling utilities to capture the savings from incremental cost reductions.[37]

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opportunity cost to managers of the marginal unit of labor.

[36] A similar theme was echoed by many other utility executives. For example, in a 1993 news story on PECO's early retirement plan, Chairman and CEO Joseph Paquette described "trying to improve the company's competitive position by emphasizing a more productive work force. Employees are receiving extensive training for quality, and the company is looking at modifying its salary structures to promote pay for performance. Paquette said such programs are needed to help the company conduct business in an evolving, less-regulated power generation environment. 'We have to be prepared for this more competitive world,' he said" ("Philadelphia Electric: Cites Effect of Cost-Cutting Plan," *Dow Jones News Service*, May 27, 1993).

[37] As noted earlier, some of these changes may have also affected utilities in non-restructuring states. For example, the number of utility rate cases dropped dramatically in the 1990s, implying that many utilities may have been short- or medium-run residual claimants to cost reductions. Knittel (2002) identifies a number of incentive regulations adopted in various jurisdictions during the 1990s. Many of the fuel-related

In this work, we allow restructuring effects to begin with the opening of formal hearings on restructuring. The primary variable of interest, *RESTRUCTURED*, is an indicator variable that turns on for investor-owned plants with the start of formal proceedings in a state that eventually passed restructuring legislation.[38] If utilities did not respond until restructuring legislation or regulation was enacted and the policy uncertainty resolved, *RESTRUCTURED* will underestimate the true effect by averaging in nonresponse years. To evaluate this possibility we introduce a second variable, *LAW PASSED*, an indicator equal to one beginning in the year the state passes restructuring legislation.[39] A third variable, *RETAIL ACCESS*, indicates the start of retail access for plants in the states that implemented retail competition within our sample.[40] If actual implementation of retail access and the associated wholesale market reforms is important to efficiency gains, it will be reflected in an incremental effect of *RETAIL ACCESS*.

To compare differences in the path of municipally-owned plants over the restructuring time period, we define the indicator variables *MUNI*POST 1987* and *MUNI*POST 1992*. The first is equal to one for all non-investor-owned plants after 1987,

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regulations (modified pass-through clauses, heat rate and equivalent availability factor incentive programs) were strongly correlated with ultimate restructuring. Some of the broader regulations (e.g., price caps and revenue decoupling programs) were almost orthogonal to eventual restructuring.

[38] The *RESTRUCTURED* variable is based on whether a state had passed legislation as of mid-2001. To date, there has been no additional restructuring and some states have delayed or suspended planned restructuring activity in the aftermath of the California electricity crisis. Plants are assigned to the state in which they are regulated. A plant located in one state may be owned by a company with exclusive service territory in a different state. In this case, the ownership state is the one for which the regulatory policy is measured. Some plants are owned by a company with service territory in more than one state and some plants are owned by several companies that are regulated by different states. In the regression analysis, we found that separately characterizing "mixed" regulation and "shared" plants had very little impact on our results.

[39] There is on average about a 2.6-year lag between the initiation of hearings and the passage of the law. We have experimented with a number of alternative measures of restructuring activity, including variables that begin with hearings regardless of restructuring outcomes, those that measure years since hearings were initiated for states that eventually restructured, and the presence of restructuring-associated rate freezes. None of these materially changes the conclusions we draw below.

[40] While *RESTRUCTURED* indicates approval of retail access competition, the specified phase-in of retail access was often slow. Only seven states implemented retail access during our sample period, four in 1998 and three in 1999.

the second for all non- IOU plants after 1992. *MUNI*POST 1987* allows for the possibility that relative input demand growth for IOU and publicly-owned plants diverged in the late 1980s and early 1990s, when many states began to experiment with incentive regulation and during which time the earliest discussion of increased competition took place. *MUNI*POST 1992* captures the incremental change in relative input demand growth across IOUs and publicly-owned plants during the restructuring period. Because the designation of the pre-reform period is inherently imperfect, we also report the unrestricted annual time path of input demand growth (see Figures 1 and 2).

Details on the data sources and summary statistics are provided in the data appendix. Table 1 reports summary statistics for plant-level data in 1985 across three categories: investor-owned plants in states that eventually restructured, investor-owned plants in states that did not restructure, and non-IOU (*MUNI)* plants. We use 1985 to ensure that comparisons are made prior to any significant changes across states in the competitive or regulatory environment, even well before restructuring initiatives.

This table suggests that the plants in these groups are not random draws from the same population. The first three variables measure employees and nonfuel operating expenses, scaled by the plant's capacity, and fuel use in millions of British thermal units (mmBtus), scaled by the plant's output. In 1985, before state-level restructuring initiatives were considered, IOU plants in states that eventually restructured used more employees and nonfuel operating expenses per MW of capacity than did IOU plants in non-restructuring states (see the difference in means test in column 4). Employment by municipally-owned plants is not statistically distinguishable from employment at restructuring IOU plants, but *MUNI* plants appear to have lower levels of nonfuel expenses. Differences in heat rates and capacity factors are not significant for any cross-sample comparison. The last four rows suggest notable differences in the stock of plants across these three groups. Although IOU plants are very similar in size across regimes, MUNI plants tend to be substantially smaller. IOU plants in restructuring states tend to be older, more likely to use gas, and less likely to use coal, than their counterparts in non-restructuring states. IOU plants in restructuring states also tend to be older and less likely to use coal than their *MUNI* counterparts. The regression analysis will control for these differences directly or with the use of plant-epoch effects.

If investor-owned utilities achieved efficiency improvements when facing impending restructuring of the generation sector, one would expect to see a relative decrease in the cost of generation for affected companies, and little difference in the change in transmission and distribution costs between the affected and not affected states since restructuring programs leave transmission and distribution comparatively untouched. If restructuring did not affect operating efficiency in the generation sector, we might expect similar changes in generation expenses across restructuring and non-restructuring companies, and perhaps similar patterns of cost changes across the transmission, distribution, and generation sectors.

Table 2 displays the mean changes in cost per MWh for investor-owned utilities in restructuring and non-restructuring states between 1990 and 1996.[41] Unlike distribution and transmission costs, generation costs per MWh decrease considerably over this period, and by considerably more at companies in restructuring states, significant at the 6 percent level. Moreover, the difference in cost changes across regimes is not significant for either the transmission or distribution costs. These aggregate statistics may suggest that the

[41] For this analysis, we rely on data reported annually by utility companies to the FERC in the Form 1, page 320, 321, and 322 respectively. We use a balanced sample composed of all companies with data reported for all three sectors in both 1990 and 1996. This amounts to 48 companies in states that did not restructure and 72 in states that did restructure.

division of the utility company faced with competition (the generating sector) responded with a decrease in costs, while other sectors and companies not faced with competition did not share this response.

IV. Estimating the Effects of Restructuring on Input Use

Following equation (11), we estimate the influence of restructuring on the use of input *N* (*EMPLOYEES, NONFUEL EXPENSE,* and *BTUs*) with the following basic regression model:

$$(12) \quad \ln(N_{irt}) = \beta_1^N \ln(\mathit{NET\ MWH}_{irt}) + \beta_2^N \ln(\mathit{PRICE}^N_{irt}) + \beta_3^N \mathit{SCRUBBER}_{irt} + \varphi_r^N \mathit{IOU{*}RESTRUCTURED}_{irt} + \gamma_{87}^N \mathit{MUNI{*}POST\ 1987}_{irt} + \gamma_{92}^N \mathit{MUNI{*}POST\ 1992}_{irt} + \alpha_i^N + \delta_t^N + e_{irt}$$

where we allow for nonunity coefficients on the output term (β_1^N) for all equations and on the input price term (β_2^N on *WAGE*) in the *EMPLOYEES* equation,[42] and measure the impact of having a scrubber on plant input use with the variable *SCRUBBER*. α_i^N is a time-invariant fixed effect for input *N* at plant-epoch *i*, which may contain a state-specific and ownership-specific error that will not be separately identified. These plant-specific effects control for much of the expected variation in input use across plants arising from heterogeneous technologies, state or regional fixed factors, and basic efficiency differences. They also control for differences in the plant mix between restructuring and non-restructuring states by comparing each plant to itself over time, removing any time-invariant plant effects. As a Hausman test (Jerry Hausman, 1978) rejects the exogeneity of the plant-epoch effects, all reported results include plant-epoch fixed-effects. δ_t^N is an

[42] Recall that we do not have a price associated with nonfuel expenses, and that according to equation (10), fuel prices should not enter into the fuel input function. We experimented with using a variable measuring the price of a given plant's fuel relative to the prices of other fuels in the same region as an instrument for output but the variable had no power in the first stage.

industry-level effect in year t, which controls for systematic changes in input demand common to all plants in that year.

The error term, e_{irt}, combines the deviation of actual from probable output, $\beta_1^N \varepsilon_{irt}^A$, and the input *N*-specific productivity shock to plant *i* in regime *r* at time *t*, ε_{irt}^N. This error is unlikely to be independent over time for a given plant; the data suggest considerable persistence in input shocks, particularly for labor, from year to year. The estimated *rho* assuming a first-order serial correlation process ranges from roughly 0.33 for nonfuel expenses to 0.75 for labor. As discussed earlier, the estimation must also account for endogeneity of output, measured in these specifications as the net generation by the plant in megawatt-hours (*NET MWH*). We therefore implement a GLS-IV estimation strategy, using a Prais-Winsten GLS correction for first-order serial correlation at the plant level,[43] and instrumenting for plant output with a nonlinear function of state demand (the log of total state electricity sales, which is a consumption rather than production measure).[44]

We consider specifications that include interactions of *IOU* ownership with the three primary restructuring indicator variables described in section III: *RESTRUCTURED, LAW PASSED,* and *RETAIL ACCESS.* In the input regressions, a negative coefficient on the restructuring variables would imply increased input efficiency associated with the regulatory reform. The core results for the input analysis are presented in table 3 for *EMPLOYEES*, table 4 for *NONFUEL EXPENSES* and table 5 for *BTU.* We first discuss the results for employment and nonfuel expenses, and then discuss the results for fuel use.

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[43] Reported standard errors also correct for possible correlation across observations at the state-year level.
[44] State demand is an important determinant of plant-level output, but should be unaffected by plant productivity shocks. The F-statistic on the instrument from the first stage estimates for the *NONFUEL EXPENSE* and *BTU* specifications (i.e. excluding the *WAGE* variable) is 11.9. We have explored the sensitivity of our results to alternative instrument choices; these are reported in the FRW (2007) Technical Appendix.

Column 1 of tables 3 and 4 reports results from generalized least squares (GLS) estimation of our basic specification, treating plant output as exogenous. The primary coefficient of interest, *IOU*RESTRUCTURED,* captures the mean differential in input use for investor-owned plants in states that eventually pass restructuring legislation. This is , measured over the period following the first restructuring hearings, relative to the untreated IOU plants in non-restructuring states. The results suggest statistically and economically significant declines in input use associated with regulatory restructuring. Employment declines by roughly 3 percent (1 percent standard error) and nonfuel expenses decline by roughly 9 percent (2 percent standard error),[45] relative to IOU plants in regimes that have not restructured.[46]

The second notable result is the dependence of the implied restructuring effect on the control group. While IOU plants in restructuring states exhibit modest reductions in employment and nonfuel expenses relative to IOUs in non-restructuring states, the implied reductions are substantially larger when compared to public and cooperative plants. The positive *MUNI*POST 1987* coefficients suggest that all IOU plants improved their efficiency relative to *MUNI* plants during the late 1980s and early 1990s. This gap widened further after 1992 (see *MUNI*POST 1992*). This suggests that even IOU plants in non-restructuring regimes improved their relative input use to a significant extent, perhaps in response to latent threats of increased competition and restructuring. Employment use was 6 percent lower for IOU plants in restructuring states relative to

[45] We use $[\exp(\varphi_r^N)-1]*100$ to approximate the implied percentage effect of *IOU* RESTRUCTURED* on input use.
[46] Note that the Cobb-Douglas functional form assumption for labor and nonfuel expenses suggests that the coefficient on output should be one, substantially larger than the coefficients estimated in these regressions. We have estimated production functions in *EMPLOYEES* and *NONFUEL EXPENSES* using more flexible functional forms than Cobb-Douglas, and the results also suggest efficiency gains associated with restructuring. We have also estimated instrumental variables versions of equations (7) and (8) that include the other input instead of output and obtained very similar results to those reported here.

MUNI plants after 1992, and nonfuel expenses declined by 11 percent relative to the *MUNI* benchmark (computed as the *IOU*RESTRUCTURED* minus *MUNI*POST 1992* coefficients in tables 3 and 4). We return to this issue in greater detail below.

The remaining columns in each table report instrumental variables (GLS-IV) estimates of the input equations that treat potential measurement error and simultaneity bias with respect to output, as well as serial correlation of shocks. For *EMPLOYEES*, estimates of the output coefficient almost double relative to the GLS estimates, although the imprecision of the GLS-IV estimates make it impossible to reject equivalence, and in absolute magnitude, both estimates of the labor demand elasticity with respect to output are quite small, at 4 percent (0.5 percent standard error) for GLS and 7 percent (7 percent standard error) for GLS-IV. Consistent with this, the estimated effect of restructuring on labor demand is essentially unaffected by the treatment of output exogeneity. For *NONFUEL EXPENSES*, however, instrumenting for output increases its estimated elasticity more than fourfold, to over 50 percent (9 percent standard error). This is consistent with a negative correlation of input shocks and output, as for example, if large maintenance expenditures are associated with outages at the plant. With the strong link between output and nonfuel expenses implied by these results, correcting for output endogeneity also has a substantial effect on the estimated effect of restructuring. The estimated coefficient on the *IOU*RESTRUCTURED* coefficient drops by almost half, to -5 percent (2.6 percent standard error), bringing it into the range of the estimated labor input effect.

Columns 3 and 4 of the tables explore robustness to alternative measures of restructuring, maintaining the use of GLS-IV estimates. Measuring restructuring by *LAW PASSED* in column 3 yields smaller (and statistically indistinguishable from zero) coefficients in both the employment and the nonfuel expense regressions, perhaps because the baseline period now includes efficiency improvements made between the initiation and passage of legislation. Column 4 adds the *RETAIL ACCESS* variable. We note that its coefficient is identified by no more than two years of data in the seven states that implement retail access as of 1999, and it is not particularly stable across alternative instrument sets or to changes in the sample. In these basic specifications, the coefficient on *RETAIL ACCESS* in labor demand is quite imprecisely estimated, though the point estimate suggests an additional –3 percent (5 percent standard error) change in employment when states implement retail access. The estimated impact of retail access on nonfuel expenses is substantially larger, at -17 percent (6.5 percent), though its sensitivity to balancing the sample precludes confidence in the estimate (see footnote 25).

Finally, in column 5 of each table, we report results that use an alternative measure of competitive pressure. Policy changes in the late 1980s and early 1990s set the stage for increased nonutility generation, but the impact of that change varied substantially across states. We construct an indicator, *HIGH NONUTILITY GENERATION*, which turns on in 1993 if the plant is in a state that has above median penetration of nonutility generation as of 1993. This measure should capture any utility responses to higher intensity of actual generation competition from unregulated market participants.[47] The estimated impact of high levels of nonutility generation on employment at IOU plants is slightly smaller and noisier than *RESTRUCTURED* estimates (at -2.2 percent, standard error, 1.9 percent). For nonfuel expenses, high penetration by non utility generation appears to have no detectable direct effect on IOU plant input use (-1 percent, standard error, 3 percent).

[47] We include this in column 5 as a replacement for restructuring policy variables, but have also estimated models that include direct effects of *RESTRUCTURED* and *HIGH NONUTILITY GENERATION* as well as their interaction.

In the instrumental variables results, as in the GLS results, the implied magnitude of the restructuring effect depends upon the chosen benchmark or control group. The gap in IOU input demand between restructuring and non-restructuring states, conditional on output, is generally statistically and economically significant, though relatively modest. The performance gain of an IOU plant in a restructured regime relative to *MUNI* plants over the same period is larger, on the order of 6 percent reductions in employment and 12 percent reductions in nonfuel expenses.[48]

To provide further insight into the question of benchmark group, we re-estimate the basic model of column (4) without the *IOU*RESTRUCTURED* and *MUNI*POST 1992* variables, but allowing for separate year effects for each of three categories of plants: IOU plants in states that eventually restructure, IOU plants in states that do not restructure, and *MUNI* plants. Figures 1 (employees) and 2 (nonfuel expenses) plot the estimated year effects for each plant group. The figures suggest greater divergence between *MUNI* and IOU plants in both input measures as the 1990s progress. As this is a period of increasing competitive pressures and substantial movement toward restructuring, these patterns suggest to us that there is considerable information in the *MUNI* benchmark comparisons.

Table 5 reports results from variants of our basic specification for fuel inputs. In column 1, GLS results suggest an output elasticity well below unity (0.912, standard error 0.004), and an implied reduction in fuel use associated with IOU plants in restructuring regimes (-1.4 percent, standard error 0.4 percent). Columns 2 through 5 report results for specifications that instrument for output. The estimated output elasticity is quite close to, and statistically indistinguishable from, unity. The estimated effects of restructuring or

[48] The results are robust to a variety of more flexible specifications of the *MUNI* controls over time and to

NON UTILITY GENERATION competition are all small and statistically indistinguishable from zero (negative in columns 2 and 4, positive in columns 3 and 5). There is no measurable effect of restructuring on fuel efficiency relative to IOU plants in non-restructuring states. Nor is there evidence of significant differences between IOU plants and *MUNI* plants. The *MUNI *POST 1992* coefficient point estimates appear virtually identical to the IOU restructuring coefficients, and are similarly indistinguishable from zero.[49]

While the data do not suggest gains in fuel efficiency from restructuring within our sample, a caveat is in order. Although variations on the order of even 0.5 - 1.0 percent in fuel productivity are economically significant, it may be difficult to measure these sufficiently precisely with our aggregated data. Fuel efficiency at a plant is heavily influenced by factors such as the allocation of output across units at a plant, the number of times its units are stopped and started, and for how long the units were running below their capacity. Our inability to measure or control for possible changes in these operational characteristics may make it particularly difficult to capture any changes in fuel efficiency. Improving our understanding of fuel efficiency effects seems an important direction for future research.

Testing robustness of the RESTRUCTURED effect

We have analyzed the robustness of these results to a variety of alternative specifications of the input demand equations. We report selected results below; additional robustness tests are available in our Technical Appendix. Given the null results

allowing differential *MUNI* output elasticity coefficients.

[49] We obtained similar null results when we estimated specifications using the log of plant heat rate (*BTUs/MWhs*) as the dependent variable, controlling for output.

in our basic fuel use regressions, we focus on labor and nonfuel expense input choices in this analysis.

Our first tests divide the sample along size and age lines; recall that these are the dimensions on which *MUNI* plants appear to differ from IOU plants. In tables 6 (employees) and 7 (nonfuel expenses), we report results for "larger" versus "smaller" plants (columns 1 and 2), and "old" versus "new" plants (columns 3 and 4). These are relative cuts that divide the sample at roughly the median of size (575 MW) and the median of age (oldest unit is built after 1960). For all specifications, IOU plants in restructured regimes exhibit lower input use than do IOU plants in nonrestructured regimes (see the coefficients on *IOU*RESTRUCTURED*), though the magnitude of the estimated effect varies with the subsample. Estimated IOU restructuring effects suggest very similar employment reductions at *LARGER* and *SMALLER* plants and slightly greater employment reductions at *NEW* plants than at *OLD* plants, though the point estimates are not significantly different across the subsamples. Nonfuel expense reductions appear to be greatest for *LARGER* and *NEW* plants—about twice the estimated magnitude for those at *SMALLER* and *OLD* plants. More interesting, perhaps, is the comparison to *MUNI* plants. They appear indistinguishable from IOUs in input use at *OLD* plants (see column 3 of both tables) and in employment at *LARGER* plants. For newer and *SMALLER* plants (where the *MUNI* density is greatest), the post-1992 performance gap is at least as large as in the previous tables. It is difficult to tell whether the patterns in these subsamples reflect real differences or a greater ability of the data to pin down performance effects for the denser part of the sample. Moreover, it does not appear that the overall conclusions of the earlier tables with respect to the *MUNI* benchmark are substantially affected by these sample differences.

In table 8, we consider whether the results are explained by a regression to the mean phenomenon among IOU plants: is the gain in efficiency among plants in restructuring regimes because they had on average low productivity draws prior to restructuring, and simply return to mean efficiency over time? To examine this, we identify high- and low-input use plants and investigate the extent to which efficiency gains at the higher input use plants are offset by efficiency losses at low input use plants. To separate plants into "low input" and "high input" categories, we predict input use from a regression on data for the pre-restructuring period, 1981 – 1992. We calculate the mean residual for each plant and classify plants with mean residuals above zero as "*HIGH INPUT*" and those below zero as "*LOW INPUT*." We then interact these indicators with the restructuring variables, which are post-1992, and re-run the basic regression specification allowing input responsiveness to restructuring to differ across plant type.[50]

The results in table 8 suggest that most of the restructuring-related input declines relative to IOU plants in nonrestructured regimes are associated with high input-use IOU plants, with reductions in the neighborhood of 10 percent to 12 percent (standard errors, about 3 percent) for both labor and nonfuel expenses for these plants. The coefficients on the *IOU*RESTRUCTURED*LOW INPUT* interactions are economically and statistically indistinguishable from zero, contrary to mean reversion predictions. This may suggest that the form of efficiency improvement was to bring less efficient plants into line with more efficient plants. This is consistent with discussions we have had with several utility managers, who claimed that restructuring led their firms to identify high-cost plants as those disadvantaged in the dispatch order, and to focus attention on bringing the costs of those plants closer to an efficient benchmark plant. Interestingly, the *MUNI* benchmark

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[50] The direct effects of *LOW INPUT* and *HIGH INPUT* categories are absorbed in the plant fixed effects.

suggests that *LOW INPUT MUNI* plants became more expensive, with little relative change at the *HIGH INPUT MUNI* plants after 1992.

We have implemented a number of additional robustness checks, including alternative instruments and instrument strategies and more flexible dynamics in input choice. A more complete discussion and example results are available in our Technical Appendix. Of particular note were specifications that allow for the possibility of fixed costs of input adjustments. We find that the restructuring estimates are robust to allowing inputs to respond to future as well as current output levels. Lagged values of output (following Blundell and Bond, 1998, 2000) proved to be weak instruments in our GLS-IV model.

V. Conclusion

This research provides some of the first estimates of the impact of electricity generation sector restructuring in the United States on plant-level efficiency. The results suggest restructuring may yield substantive medium-run efficiency gains. The estimates suggests that IOU plants in restructuring regimes reduced their labor and nonfuel operating expenses by three to five percent in anticipation of increased competition in electricity generation, relative to IOU plants in states that did not restructure their markets. The estimated efficiency gains are even larger when compared to a benchmark based on municipal, federal, and cooperative plants: on the order of six percent reductions in labor use and twelve percent reductions in nonfuel operating expenses relative to non-IOU plants over the same time period. There is little evidence of increases in fuel efficiency relative to plants in non-restructuring regimes, although the power of these tests is limited given the plausible range of possible fuel use improvements.

These same-plant reductions in input use suggest an important role for market-based incentives and competition in promoting technical efficiency, buttressing the findings of Nickell (1996), Ng and Seabright (2001), and Galdón-Sánchez and Schmitz (2002), among others. This finding is particularly interesting given the industry context. Generating plant technology is reasonably well understood by engineers, and the pre-restructuring industry was remarkably open in sharing detailed information on plant operations and input use across plants and firms.[51] Presumably, external benchmarks also were more accessible in this setting than in most industries. This could suggest that competition induced greater effort on cost reduction by increasing the sensitivity of returns to managerial and worker effort, rather than by reducing informational asymmetries over managerial effort (Nickell, 1996).

Additional work remains to be done to fill out the picture of the overall effects of restructuring on electricity industry efficiency.[52] We began by looking at operating efficiency within existing utility plants both because this is one of the few places where gains are likely to show up before restructured wholesale markets open up and because rich data are available on utility-owned plants. As our results suggest, even these data are inadequate for the fine-level analysis required to estimate within and across-plant changes in fuel efficiency. This analysis will require datasets with both cleaner measures of fuel efficiency and richer information on independent factors that affect fuel use. Finally, assessing whether investment decisions are made more efficiently after restructuring requires more time, and access to better nonutility data. Since power plants are so long-

[51] Our access to detailed, publicly-available, plant-identifiable data corroborates this.
[52] See Wolfram (2005) for a discussion of the general issues involved in assessing different types of efficiency changes accompany electricity restructuring.

lived, very few new additions are made each year, and currently we have no more than a handful of anecdotes about investment after restructuring.

It is important to recognize that these efficiency estimates are, however, only one input to judging the ultimate benefit of restructuring policies. The overall assessment depends as well on the realized magnitude of potential dynamic efficiencies, and offsetting effects from higher investment expenditures, restructuring costs, the loss of coordination and network economies within vertically integrated systems, and the exercise of market power in unregulated generation markets. Dynamic costs could be higher if restructuring reduces knowledge sharing that affects productivity growth over time. It is possible, however, that longer run benefits will be greater if firms respond to the new incentives created by restructuring with investments in both human and physical capital that further enhance efficiency. If California's crisis does not induce reversals of the restructuring movement, and regulators do not shut down data reporting and researcher access to detailed plant-level data, time may enable us to distinguish among these possibilities.

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Table 1: Summary of Plant Characteristics in 1985, By Ownership and Restructuring Regime as of 2001

Variable	*RESTRUCTURED* IOU Plants (N=249)	*NON-RESTRUCTURED* IOU Plants (N=192)	*MUNI* Plants (N=105)	Difference in Means (t-statistic): *RESTRUCTURED - NONRESTRUCTURED* IOUs	Difference in Means (t-statistic): *RESTRUCTURED* IOUs - *MUNI*
EMPLOYEES / MW	0.29	0.26	0.27	0.04**	0.02
	(0.22)	(0.14)	(0.13)	(2.07)	(1.12)
NONFUEL EXPENSE/ MW	19909	16742	15369	3167**	4539**
($/MW)	(14180)	(9976)	(9334)	(2.75)	(3.54)
HEAT RATE	11	11	12	-0.2	-0.6
(Million Btu/MWh)	(2.0)	(3.3)	(5.9)	(-0.90)	(-0.97)
CAPACITY FACTOR	0.40	0.40	0.39	-0.006	0.005
(0.0-1.0)	(0.21)	(.20)	(0.22)	(-.30)	(0.18)
MegaWatt Capacity	805	801	679	3.6	126*
(MW)	(658)	(645)	(601)	(0.06)	(1.75)
Age of Oldest Unit	28	24	19	3.5**	8.4**
(years)	(11)	(13)	(11)	(2.96)	(6.40)
Percent COAL	51	79	68	-28**	-16**
				(6.42)	(2.91)
Percent GAS	37	16	29	20**	8
				(5.03)	(1.48)

In the first three columns, standard deviations are in parentheses.
* denotes differences significant at 0.10 level ** denotes differences significant at 0.05 level or better.

Table 2: Percentage Change in Costs per MWh from 1990 to 1996

Difference of Means Tests

Investor Owned Utilities in Non-restructuring versus Restructuring States

	N	Distribution	Transmission	Generation
Restructuring Mean	72	1.5	13.1	-13.5
Non-restructuring Mean	48	-1.6	12.6	-5.1
Difference of means		3.1	0.4	-8.3
t-statistic		0.70	0.06	-1.87

All measures are in nominal dollars.

Transmission and distribution costs are per MWh sales to ultimate customers, while generation costs are per MWhs generated at company plants.

Table 3: Labor Input Demand Estimates with Alternative Specifications of Restructuring

Dependent variable: ln(*EMPLOYEES*)

Independent Variables	(1) GLS Basic	(2) GLS-IV Basic	(3) GLS-IV Law Date	(4) GLS-IV Retail Access	(5) GLS-IV Non Utility Generation
*IOU*RESTRUCTURED*	-0.032**	-0.031**		-0.031**	
	(0.014)	(0.015)		(0.014)	
*IOU*LAW PASSED*			-0.013		
			(0.016)		
*IOU*RETAIL ACCESS*				-0.031	
				(0.051)	
*IOU*HIGH NON*					-0.022
UTILITY GENERATION					(0.019)
*MUNI*POST 1992*	0.029**	0.032***	0.036***	0.031***	0.029**
	(0.012)	(0.012)	(0.012)	(0.012)	(0.014)
*MUNI*POST 1987*	0.056***	0.060***	0.061***	0.059***	0.062***
	(0.012)	(0.013)	(0.013)	(0.013)	(0.013)
ln(WAGE)	-0.010	-0.012	-0.013	-0.011	-0.013
	(0.013)	(0.013)	(0.013)	(0.013)	(0.013)
ln(NET MWH)	0.036***	0.067	0.076	0.060	0.078
	(0.005)	(0.064)	(0.065)	(0.065)	(0.064)
SCRUBBER	0.033	0.037	0.039	0.035	0.041
	(0.026)	(0.025)	(0.025)	(0.026)	(0.025)
ρ	.75	.72	.71	.72	.71

N =10079; 769 plant-epoch and 19 year effects included.

Estimates corrected for the presence of serial correlation using a Prais-Winsten transformation.

IV estimates use ln(*STATE SALES*) as an instrument for ln(*NET MWH*).

Standard errors in parentheses, clustered for correlation within a state-year.

* significant at 10 percent; ** significant at 5 percent; *** significant at 1 percent

Table 4: Nonfuel Expense Input Demand Estimates with Alternative Specifications of Restructuring

Dependent variable: ln(*NONFUEL EXPENSES*)

	(1)	(2)	(3)	(4)	(5)
Independent Variables	GLS Basic	GLS-IV Basic	GLS-IV Law Date	GLS-IV Retail Access	GLS-IV Non Utility Generation
*IOU*RESTRUCTURED*	-0.095***	-0.051**		-0.052**	
	(0.022)	(0.026)		(0.025)	
*IOU*LAW PASSED*			-0.022		
			(0.027)		
*IOU*RETAIL ACCESS*				-0.189***	
				(0.063)	
*IOU*HIGH NON UTILITY GENERATION*					-0.013
					(0.029)
*MUNI*POST 1992*	0.057***	0.069***	0.082***	0.068***	0.079***
	(0.019)	(0.021)	(0.022)	(0.020)	(0.023)
*MUNI*POST 1987*	0.121***	0.109***	0.108***	0.110***	0.108***
	(0.020)	(0.022)	(0.022)	(0.021)	(0.023)
ln(NET MWH)	0.077***	0.417***	0.445***	0.379***	0.454***
	(0.011)	(0.090)	(0.091)	(0.091)	(0.091)
SCRUBBER	0.025	0.051	0.055	0.040	0.059
	(0.038)	(0.050)	(0.053)	(0.048)	(0.053)
ρ	.38	.33	.34	.33	.34

N = 10079; 769 plant-epoch and 19 year effects included.

Estimates corrected for the presence of serial correlation using a Prais-Winsten transformation.

IV estimates use ln(*STATE SALES*) as an instrument for ln(*NET MWH*).

Standard errors in parentheses, clustered for correlation within a state-year.

* significant at 10 percent; ** significant at 5 percent; *** significant at 1 percent

Table 5: Fuel Input Demand Estimates with Alternative Specifications of Restructuring

Dependent variable: ln(*BTUs*)

Independent Variables	(1) GLS Basic	(2) GLS-IV Basic	(3) GLS-IV Law Date	(4) GLS-IV Retail Access	(5) GLS-IV Non Utility Generation
*IOU*RESTRUCTURED*	-0.014***	-0.009		-0.009	
	(0.004)	(0.006)		(0.006)	
*IOU*LAW PASSED*			0.005		
			(0.007)		
*IOU*RETAIL ACCESS*				0.007	
				(0.017)	
*IOU*HIGH NON UTILITY GENERATION*					0.005
					(0.008)
*MUNI*POST 1992*	-0.004	-0.005	-0.003	-0.005	-0.001
	(0.005)	(0.007)	(0.007)	(0.007)	(0.007)
*MUNI*POST 1987*	0.004	0.000	0.000	0.000	0.000
	(0.006)	(0.009)	(0.009)	(0.009)	(0.009)
ln(NET MWH)	0.912***	0.969***	0.979***	0.970***	0.978***
	(0.004)	(0.034)	(0.035)	(0.036)	(0.034)
SCRUBBER	-0.008	-0.003	-0.001	-0.003	-0.002
	(0.009)	(0.010)	(0.010)	(0.010)	(0.009)
ρ	-.08	.44	.44	.44	.44

N = 10002; 768 plant-epoch and 19 year effects included.

Estimates corrected for the presence of serial correlation using a Prais-Winsten transformation.

IV estimates use ln(*STATE SALES*) as an instrument for ln(*NET MWH*).

Standard errors in parentheses, clustered for correlation within a state-year.

* significant at 10 percent; ** significant at 5 percent; *** significant at 1 percent

Table 6: Labor Input Demand Estimates by Plant Type

Dependent variable: ln(*EMPLOYEES*)

	(1)	(2)	(3)	(4)
Independent Variables	Larger Plants 575MW+	Smaller Plants < 575 MW	Old Plants < 1960	New Plants 1960+
*IOU*RESTRUCTURED*	-0.030**	-0.031	-0.025	-0.033***
	(0.015)	(0.020)	(0.020)	(0.012)
*MUNI*POST 1992*	0.018	0.039**	-0.001	0.036***
	(0.016)	(0.015)	(0.023)	(0.012)
*MUNI*POST 1987*	0.016	0.086***	0.092***	0.039***
	(0.021)	(0.016)	(0.028)	(0.013)
ln(WAGE)	0.004	-0.021**	-0.034	-0.005
	(0.027)	(0.010)	(0.038)	(0.020)
ln(NET MWH)	0.054	0.047	0.085	0.013
	(0.118)	(0.054)	(0.059)	(0.100)
SCRUBBER	0.068	-0.027	-0.001	0.055*
	(0.043)	(0.019)	(0.031)	(0.032)
ρ	.71	.74	.70	.73
Observations	5016	5063	5113	4966

Plant-epoch and year effects included.

All estimates are GLS-IV using a Prais-Winsten transformation for serial correlation and ln(*STATE SALES*) as an instrument for ln(*NET MWH*).

Standard errors in parentheses, clustered for correlation within a state-year.

* significant at 10 percent; ** significant at 5 percent; *** significant at 1 percent

Table 7: Nonfuel Expense Demand Estimates by Plant Type

Dependent variable: ln(*NONFUEL EXPENSES*)

	(1)	(2)	(3)	(4)
	Larger Plants	Smaller Plants	Old Plants	New Plants
Independent Variables	575MW+	< 575 MW	< 1960	1960+
*IOU*RESTRUCTURED*	-0.072**	-0.034	-0.034	-0.068***
	(0.029)	(0.032)	(0.036)	(0.025)
*MUNI*POST 1992*	0.078***	0.061**	0.019	0.080***
	(0.030)	(0.027)	(0.043)	(0.024)
*MUNI*POST 1987*	0.052*	0.149***	0.144***	0.102***
	(0.031)	(0.026)	(0.037)	(0.027)
ln(NET MWH)	0.464***	0.342***	0.430***	0.369***
	(0.146)	(0.092)	(0.110)	(0.121)
SCRUBBER	-0.032	0.178***	0.101	-0.057
	(0.057)	(0.066)	(0.063)	(0.058)
ρ	.35	.30	.33	.31
Observations	5016	5063	5113	4966

Plant-epoch and year effects included.

All estimates are GLS-IV using a Prais-Winsten transformation for serial correlation and ln(*STATE SALES*) as an instrument for ln(*NET MWH*).

Standard errors in parentheses, clustered for correlation within a state-year.

* significant at 10 percent; ** significant at 5 percent; *** significant at 1 percent

Table 8: Tests for Mean Reversion in Restructuring Effects on Input Demand

	Dependent Variable			
Independent Variable	*ln(EMPLOYEES)*		*ln(NONFUEL EXPENSES)*	
	**LOW INPUT PLANT*	**HIGH INPUT PLANT*	**LOW INPUT PLANT*	**HIGH INPUT PLANT*
*IOU*RESTRUCTURED*	0.017	-0.100***	0.009	-0.118***
Interaction	(0.012)	(0.027)	(0.028)	(0.030)
*MUNI*POST 1992*	0.086***	-0.010	0.122***	0.006
Interaction	(0.019)	(0.014)	(0.027)	(0.023)
*MUNI*POST 1987*	0.063***		0.109***	
	(0.013)		(0.021)	
ln(WAGE)	-0.012			
	(0.013)			
ln(NET MWH)	0.080		0.405***	
	(0.064)		(0.091)	
SCRUBBER	0.024		0.042	
	(0.022)		(0.046)	
ρ	.70		.33	

N = 9784; 702 plant-epoch and 19 year effects included.
All estimates are GLS-IV using a Prais-Winsten transformation for serial correlation and ln(*STATE SALES*) as an instrument for ln(*NET MWH*).
Standard errors in parentheses, clustered for correlation within a state-year.
* significant at 10 percent; ** significant at 5 percent; *** significant at 1 percent

Figure 1: Labor Input Demand Year-Effects by Regulatory Status (Basic GLS-IV Specification)

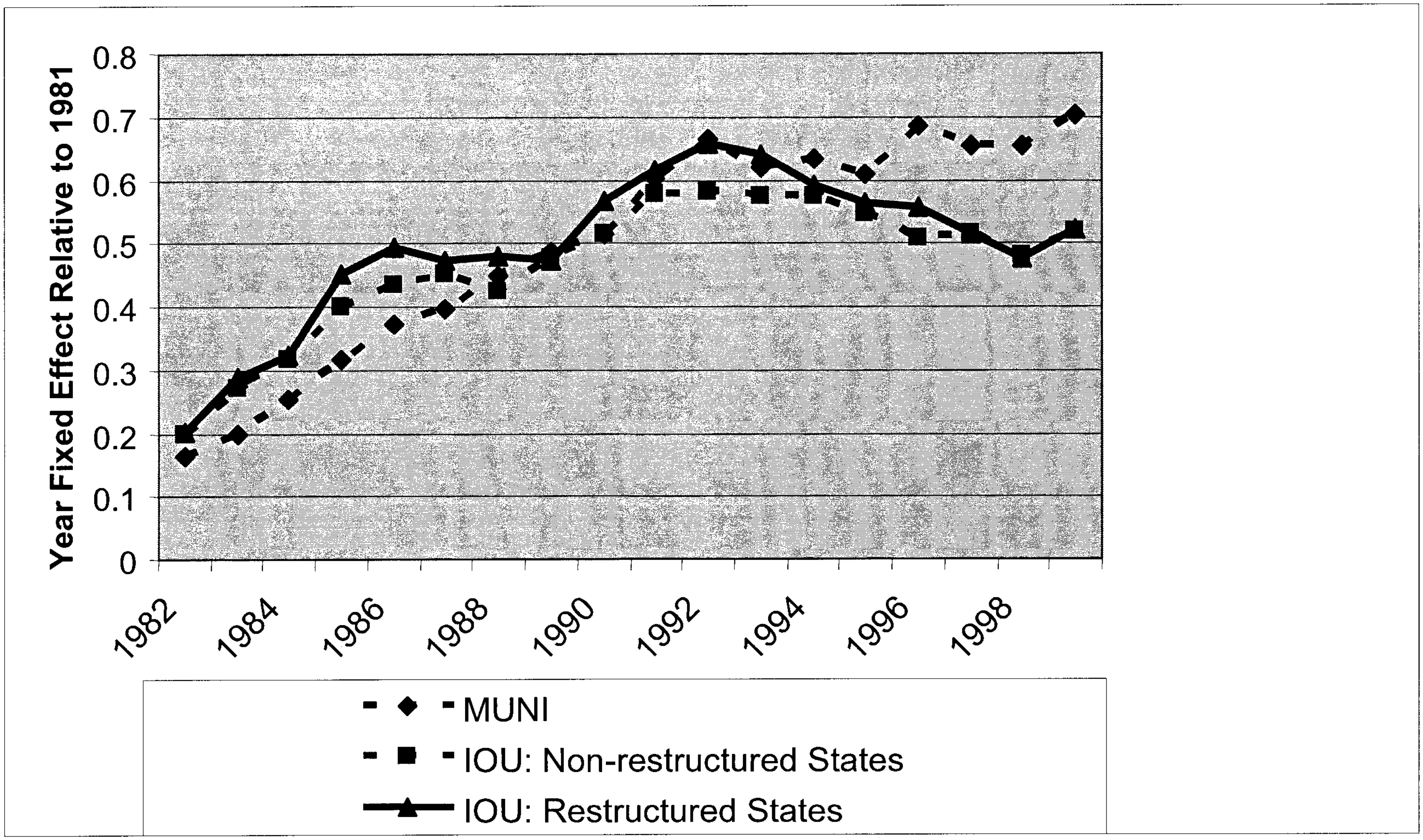
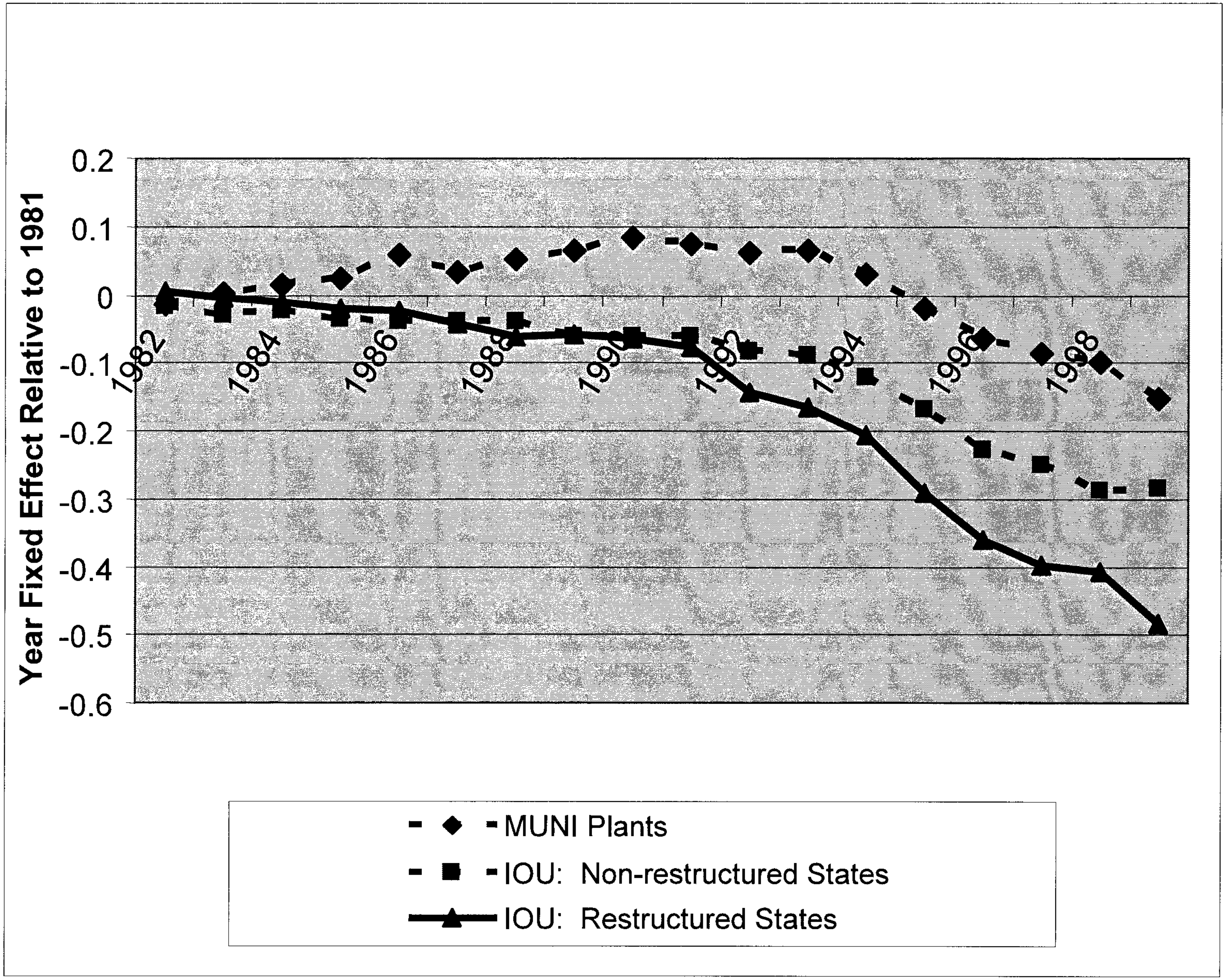


Figure 2: Nonfuel Expense Input Demand Year-Effects by Regulatory Status (Basic GLS-IV Specification)



Data Appendix

Sample Construction:

This study analyzes productivity for large fossil-fueled steam turbine or combined cycle plants. The core data source is the Utility Data Institute (UDI) O&M Production Cost Database. UDI develops this from the annual FERC Form 1 (filed by investor-owned utilities), EIA Form 412 (filed by municipal and other government utilities), and RUS Form 7 & 12 (filed by electric cooperatives) filings. We construct the sample used in the empirical analysis as follows:

Plant type: We exclude alternative fuel plants (wood, geothermal, waste; 14 plants, 196 plant-years). We restrict the sample to steam turbine (ST) and combined cycle (CC) plants, based on the variable OMPTYPE in the UDI database. This excludes 564 combustion (gas) turbine only (GT) plants, 6487 plant-year observations. [53]

Plant-epoch: Plant-epochs consist of plant-years over which plant capacity is relatively constant, i.e. reported capacity changes are less than 40 MW and 15 percent.

Plant size: We retain plant-year observations as long as they are part of a plant-epoch with mean capacity (gross megawatts) above 100 MW and at least 3 years of operations at a scale above 100 MW. The mean capacity test excludes 229 plant-epochs (186 plants, 2142 plant-years); the 3-year operations test excludes an additional 117 plant-epochs (171 plant-years). The latter test also excludes plant-epochs for which we only have one or two years of data, typically plants that add or retire capacity near the beginning or end of our sample period. Excluding these seemed appropriate

[53] Most of these are small; the majority report incomplete data. In many cases, these appear (based on plant names and locations) to report information for auxiliary gas turbines located on the same site as units with large steam turbines: e.g., Alamitos, a 1900 MW plant with 6 steam units and Alamitos GT, a 140 MW jet engine unit are separate observations in our dataset. The basic restructuring results are robust to including all large GT plant observations with nonmissing data as additional plants, and to aggregating GT plant data with their identifiable associated base plants (using plant name and location). See column (2) in tables T5 and T6 in the FRW (2007) Technical Appendix.

given plant-epoch fixed effects and the Prais-Winsten-differenced GLS estimation techniques we use.

Incomplete plant data: We drop 274 plant-years with missing or nonpositive output data; 80 plant-years with missing or nonpositive nonfuel expenses; 204 plant-years with missing employment and 289 plant-years with zero reported employees. Observations excluded for missing data do not seem to be directly related to restructuring, and in some cases are less frequent in restructuring states, conditional on year.[54]

Outlier analysis: Stata's dfbeta regression diagnostics were used to ensure that the results are robust to outliers. The dfbeta statistic measures how much a coefficient estimate changes (relative to its standard error) when an observation is omitted. For the basic employment and nonfuel expense model, we calculated dfbeta statistics for all observations for the variables *ln(NET MWH)*, *SCRUBBER*, *ln(WAGE)* for the employment input model, *IOU*RESTRUCTURED*, *MUNI*POST 1992*, and *MUNI*POST 1987*. We excluded 148 observations that moved coefficient estimates in either or both of the employment or the nonfuel regressions by more than 0.1 standard errors. We found little evidence of a pattern in the observations that are dropped this way. For instance, we drop at least 4 observations from every year, and the most observations dropped from any year are 21 from 1998. These deletions change the coefficient point estimates relatively little and serve mainly to clean the data of extreme outliers that inflate the standard errors, as reported in columns (3) and (4) of our Technical Appendix tables T5 and T6. We note that the coefficient on *IOU*RESTRUCTURED* in the labor input equation changes only slightly (from 0.31 in our basic

[54] For example, regression of the percent of plants in a state-year observation with missing or zero employee data on time since restructuring indicator (min (0, the number of years since the start of formal hearings in the state), year dummy variables, and state fixed effects suggests that the percentage of such missing values actually *decreases* following restructuring.

specification on the trimmed sample to 0.26 in the untrimmed sample) though it is significantly distinguishable from zero only at the 11 percent level for the untrimmed sample.

The resulting basic dataset consists of 10,079 observations on 647 plants, allocated to 779 plant-epochs.

Fuel Input Dataset: The fuel input dataset begins with the basic dataset described above. We eliminate observations with missing fuel data and apply Stata's dfbeta regression diagnostics to an estimate of the fuel input equation, using a process and thresholds similar to that described for employment and nonfuel expenses. This resulted in deletion of an additional 77 observations. Since most of the analysis that we report in the paper is based on the employment and nonfuel specifications and since the fuel data appear considerably noisier, this smaller dataset is used only for the fuel input analysis. It consists of 10,002 observations on 646 plants, 778 plant-epochs.

Table A1: Summary of Variables (N=10079 unless otherwise noted)

Variable	Definition	Mean (Standard Deviation)
Output and Input Variables		
ln(NONFUEL EXPENSE)	ln (Annual non fuel production expenses ($)), calculated as the total production expense less fuel expense.	16.036 (0.940)
ln (EMPLOYEES)	ln (Annual mean number of employees)	4.739 (0.815)
ln(BTU)	ln(Total of the total btus of fuel consumption). Calculated as (tons of coal * 2000 lbs/ton* btu/lb) + (barrels of oil*42 gal/barrel*btu/gal) + (Mcf gas*1000 cf /mcf*btu/cf). These use reported annual plant-specific btu content of each fuel. (*N* = 10002)	30.547 (1.291)
ln(NET MWH)	ln (Annual net MWh generation)	14.329 (1.396)
Utility and Restructuring Variables		
IOU	1 for plants classified as IOU, holding, or private companies; 0 otherwise.	0.802
MUNI	1 for plants owned by utilities classified as government or cooperative utilities; 0 otherwise.	0.197
*IOU*RESTRUCTURED*	1 for IOU plants in states that restructured, beginning in the year of the first formal hearing; 0 otherwise.	0.108
*IOU*LAW PASSED*	1 for IOU plants in states that restructured, beginning in the year that legislation was enacted; 0 otherwise.	0.041
*IOU*RETAIL ACCESS*	1 for IOU plants in states that restructured, beginning in the first year of retail access; 0 otherwise.	0.006
*MUNI*POST 1987*	1 for MUNI plants in years 1988-1999; 0 otherwise.	0.133
*MUNI*POST 1992*	1 for MUNI plants in years 1993-1999; 0 otherwise.	0.074
*IOU*HIGH NON UTILITY GENERATION*	1 beginning in 1993 for IOU plants in states with above median penetration of nonutility generating plants in 1993; 0 otherwise.	0.103

LOW INPUT	1 if plant mean residual from the relevant input use regression for 1981-1992 period is below zero; 0 otherwise (N=9784).	0.500 (0.500)
HIGH INPUT	1 if plant mean residual from the relevant input use regression for 1981-1992 period is above zero; 0 otherwise (N=9784).	0.500 (0.500)
Other Variables		
SCRUBBER	1 if there is an FGD scrubber at the plant; 0 otherwise.	0.132
ln(WAGE)	Bureau of Labor Statistics annual wage bill divided by total employment calculated at the state-year level separately for IOU and MUNI plants. Numbers are imputed for MUNI plants in 18 states over various years and for IOU plants in 6 states from 1997-1999.	10.532 (.335)
Plant Characteristic Variables		
LARGER	1 if the plant capacity (Gross MW) is at least 575MW.	0.498 (0.500)
SMALLER	1 if the plant capacity (Gross MW) is less than 575 MW.	0.502 (0.500)
OLD	1 if the youngest unit at the plant entered service before 1960.	.507 (.500)
NEW	1 if the youngest unit at the plant entered service in 1960 or later.	.493 (.500)
Economic and Weather Variables		
ln(STATE SALES)	ln (Total state electricity consumption by year in gigawatthours)	11.184 (0.851)
ANNUAL_HDDAYS	Population-weighted heating degree days for each state-year (use MD for DC); $N = 10069$.	4399.468 (2138.744)
ANNUAL_CDDAYS	Population-weighted cooling degree days for each state-year (use MD for DC); $N = 10069$.	1432.163 (1.396)

Data Sources:

Plant characteristics and operating data: UDI O&M Production Cost Database

Wages: U.S. Department of Labor, Bureau of Labor Statistics. Industry state-level annual wage bill divided by industry total employment.

Electric utility wages: SIC Industries 4911.

Comparable sector wages: Average over SIC industries 4923-4925 (natural gas distribution), 4953 (hazardous waste treatment), and 2911 (petroleum refining).

Utility ownership: UDI Utility Datapak Book, 1997.

Restructuring variables: Restructuring status and timing is compiled from a review of

(1) U.S. Department of Energy, Energy Information Administration (EIA), "The Changing Structure of the Electric Power Industry: An Update, 12/96"

(2) EIA, "The Changing Structure of the Electric Power Industry: 2000 An Update"

(3) EIA, "Status of State Electric Industry Restructuring Activity," Timeline as of July 2002

(4) Edison Electric Institute "Electric Competition in the States" February, 2001

(5) National Association of Regulatory Utility Commissioners (NARUC), "Utility Regulatory Policy in the United States and Canada, Compilation," 1994 – 1995, and 1995 – 96

(6) The Council of State Governments, "Restructuring the Electricity Industry," 1999

(7) State Public Utility Commission websites, relevant legislation and reports.

State demand data and instruments:

State electricity sales by year: Sales to Ultimate Customers from EIA's "Electric Sales and Revenue," Table 6, and EIA's "Electric Power Annual," Tables 117 and 90, various years.

Heating and cooling degree days: Population-weighted heating and cooling degree days by state-year (using Maryland for Washington, D.C.) are from U.S. Dept. of Commerce, National Oceanic and Atmospheric Administration, Historical Climatology Series, "Monthly State, Regional, and National Heating Degree Days Weighted By Population," various years.

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The Benefits of Electric Restructuring to Pennsylvania Consumers

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ON BEHALF OF THE
ELECTRIC POWER GENERATION ASSOCIATION (EPGA)
AND THE
ELECTRIC POWER SUPPLY ASSOCIATION (EPSA)

Electric Power Generation Association

epsa® Electric Power Supply Association

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EXECUTIVE SUMMARY

Electric industry restructuring has provided real and measurable benefits to Pennsylvania consumers and businesses. Spurred by competition over the past decade, Pennsylvania power plants have reached unprecedented levels of efficiency. For example, the state's nuclear plants alone generate almost two million megawatt-hours more electricity than they did in 1996, enough to power almost 170,000 homes. Improved nuclear operating efficiencies alone are saving consumers many millions of dollars each year. Best of all, Pennsylvania consumers paid nothing for these improvements and no longer bear the financial risks of failed generating plants or cost overruns, as they did under the old regulatory system. Furthermore, under competition, innovative providers of energy conservation and consumer demand response resources are growing rapidly.

There are no "silver bullets" policymakers can use to prevent an increase in electric prices. Neither regulation nor competition can prevent a future Hurricane Katrina from wrecking natural gas infrastructure and causing natural gas prices to soar. Neither can they prevent the tremendous increases in worldwide demand for fossil fuels that have driven electric prices higher. But, unlike regulation, strong market forces exist under competition that, when allowed to function properly, can provide the lowest available cost to consumers.

The move to competitive markets did not, and will not, eliminate the necessary role of policymakers. Government policies can establish a framework that fosters competition, addresses environmental realities, and encourages more efficient use of resources. Government policies can promote new resource investments by reducing regulatory uncertainty and the financial risks that arise when market rules suddenly change. Government policies can also encourage resource diversity by moving toward value-based prices, which will facilitate development of new generation and transmission infrastructure and will promote consumer demand response by sending appropriate market signals.

The reality is that no amount of government intervention, however well-intentioned, can change the basic principles of supply and demand. Rather than rejecting market forces, a better approach is to embrace and apply those market forces to create an even more robust, competitive market for electricity consumers in Pennsylvania.

- Prior to electric competition in Pennsylvania, retail customers in Pennsylvania absorbed significant and steady rate increases resulting from a number of factors, including inefficient operations, construction cost overruns and higher fuel prices.
- In response, in 1996 Pennsylvania passed the "Electricity Generation Customer Choice and Competition Act" which shifted generation construction and operation risk from consumers, provided market incentives to improve plant efficiency and promoted competition and innovation in retail electric markets.
- Pennsylvanians have benefited by millions of dollars each year from more efficient generation with increased output and lower operating costs and new market entrants providing both innovative generation and demand side response programs.
- The expiration of multi-year capped rates, which have provided consumers billions of dollars in benefits, presents a transitional challenge for consumers. But enacting new legislation that attempts to counter competitive market forces is not the answer.
- In the end, it is the market itself that provides a self-correcting mechanism to resolve transient price increases. Unlike more regulation, competition will provide the lowest available cost. Therefore, the better answer is to apply competitive procurement principles, while at the same time pursuing rate mitigation strategies such as energy efficiency and demand response programs and rate phase in and budget plans to ease the transition to market prices for all consumers.

INTRODUCTION[†]

As the Pennsylvania Legislature considers a number of bills affecting the energy industry, it is important to consider the benefits derived from restructuring the state's electric industry. Although expiring multi-year capped rates present transitional challenges for consumers, enacting new legislation that attempts to counter market forces is not the answer, nor is it feasible. Governments cannot legislate away basic economic principles of supply and demand. Most significantly, post rate cap price increases are not caused by electric restructuring and wholesale competition, but primarily by substantial increases in fossil fuel prices; increases that were not anticipated in the late 1990s. On the contrary, restructuring and wholesale competition have helped mitigate larger price increases that likely would have occurred under the traditional regulatory framework.

Electric restructuring was never intended to guarantee that electricity prices would forever decline. No market, either competitive or regulated, can provide such a guarantee. Ultimately, electricity prices must reflect the actual costs of power, costs that have risen substantially in the last ten years. All competitive markets are subject to price increases when demand outstrips supply. It is the market itself that provides a self-correcting mechanism to resolve such transient price increases.

[†] This report was sponsored by the Electric Power Generation Association (EPGA) and the Electric Power Supply Association (EPSA).

As policymakers in Pennsylvania consider various energy legislative proposals this Fall, they can benefit from a few key facts. First, the underlying rationale for electric industry restructuring was to address long-term problems within the historic "command-and-control" regulatory framework. Second, despite some pronouncements to the contrary, the benefits of electric restructuring are both real and substantial. Third, there are effective transition mechanisms that can be used to ease the burden of any sudden price increases, while preserving the benefits of market competition.

WHY RESTRUCTURING? A BRIEF HISTORY

Electric restructuring occurred in large part because the existing regulatory system had failed. Although there has been much emphasis on electric price increases that follow the expiration of multi-year price caps, prior to competition under the regulated system, retail consumers in Pennsylvania absorbed significant and steady rate increases. Those increases resulted from a number of factors, including construction cost overruns, higher fuel prices, and investments in pollution control measures. Moreover, under the regulated model, generation plant owners lacked economic incentives to operate their plants more efficiently.

To address these real, recurring issues, federal and state regulators across the nation took a number of different approaches. Some state regulators required utilities to prepare so-called "least-cost" plans, in which utilities detailed how they would meet anticipated future growth in electricity demand over the next 10 to 20 years, including how much of the anticipated growth could be met cost-effectively with energy conservation measures based on complex "avoided cost" calculations. These conservation measures included everything from compact fluorescent light bulbs, to more efficient industrial motors, water heater insulation, and utility-paid fuel switching to natural gas for electric space heating and water heaters.

At the federal level, wholesale electric competition was first introduced in 1978, with passage of the Public Utility Regulatory Policies Act (PURPA),[1] which created a new class of independently-owned, small (80 mw or less) generators, called "qualifying facilities" (QFs). The goal was to encourage renewable generating resources, such as small hydroelectric plants, geothermal facilities, and wind power, and reduce the demand for natural gas. Under PURPA, individual utilities were required to purchase all of the output from QFs at a price equal to the utility's avoided cost.

The next major federal action was the Energy Policy Act of 1992, which created a second new class of independently-owned generators, called "exempt wholesale generators". To help ensure independently owned generating plants could transmit their power to users, pursuant to the Act of 1992, the Federal Energy Regulatory Commission began enacting rules allowing "open-access" to utilities' transmission lines by independent wholesale generators.

Nonetheless in the 1990s, electric rates continued to rise nationally for several reasons. First, despite conservation measures, the demand for electricity steadily increased. Second, avoided cost forecasts were frequently wrong, and locked utilities into paying above market prices under PURPA's mandatory power purchase requirements. Not for the first time, well-intentioned government mandates designed to solve certain problems had inadvertently created others.

[1] For a more detailed summary of the history of the electric industry, see J. Lesser and L. Giacchino, *Fundamentals of Energy Regulation* (Vienna, VA: Public Utilities Reports, Inc. 2007), Chapter 1.

ADDRESSING THE PROBLEMS OF ELECTRIC REGULATION

All of these impacts were evidence of an outdated regulatory system. Many customers, especially large industrial customers that faced stiff competition both in the United States and abroad, complained that rising rates were driving them out of business. They wanted access to electricity generated by natural gas because deregulation of natural gas prices had led to huge investments in exploration and development making natural gas more plentiful and cheaper. Moreover, generation developers were designing new, highly efficient gas-fired generators, called combined-cycle plants. State and national industrial lobbying groups advocated for restructuring and direct retail competition to enable their members to bypass their local utilities and purchase electricity directly from new, low-cost suppliers who were building these gas-fired combined cycle plants.

In other words, industrial consumers in Pennsylvania and nationwide wanted to rely on market competition, rather than regulation, to obtain their electricity. In all other industries, competitive markets had provided producers with the incentives to invest and innovate, while competition among producers promoted disciplined prices. Consumers benefited from the resulting increases in operating efficiency, output and, ultimately, lower market prices. Efficient producers benefited by reducing their costs below others.

Pennsylvania's "Electricity Generation Customer Choice and Competition Act" ("Competition Act) passed in 1996, enabled competitive forces to address several key economic objectives:

(1) Shift the financial risks of construction, operation, and ownership of generation from captive ratepayers to investors, who are positioned to manage those risks far more effectively.

(2) Provide market incentives for investors to build new generating plants, and operate existing plants more efficiently.

(3) Promote competition and innovation in retail electric markets, including innovative demand-side management and demand response programs.

In large part, these economic objectives have been realized. First, Pennsylvania electric consumers no longer bear the risks of uneconomic generating plant investments as they did under the old regulated model. Nor do Pennsylvanians bear the financial risks of construction cost overruns or forced outages caused by major equipment failures. Instead, those risks are borne by those who can best manage and diversify them: competitive generating companies and their investors.

Second, many studies have confirmed that competition spurred generating plants to become markedly more efficient by increasing their output and reducing their operating costs. For example, in a previous study,[2] we conservatively estimated that improved nuclear plant performance annually benefits Pennsylvania consumers by over $120 million. Moreover, that estimate does not even include the substantial benefits to Pennsylvania consumers of improved performance at nuclear plants in neighboring deregulated PJM states, such as Maryland and New Jersey.

Pennsylvania has also benefited from being a member of the PJM power pool. Competition in wholesale markets, administered by independent entities such as PJM, has been found by federal regulators to be robust.[3] Power pools like PJM

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[2] C. Cain and J. Lesser, "The Pennsylvania Restructuring Act: Economic Benefits and Regional Comparisons," February 2007.

[3] See, 2006 State of the Market Report, Vol. 1, March 8, 2007 ("2006 SOM"), at 11, available at:

exist because they capture the benefits of supply and demand. PJM diversifies supplies, thus improving overall reliability. It creates a much larger regional market, which provides Pennsylvania consumers access to the capacity of over 1,200 generators and 165,000 MW of generating capacity in 13 states.[4] By coordinating the operations of all of these generating plants, the likelihood of an outage is far less than if utilities operate separately. For example, if a plant needs routine maintenance or suddenly breaks down, other generating plants are available to meet customer demand. Power pools like PJM still need to have reserve generating capacity, but such resources can be used far more efficiently than if individual utilities separately operate their power plants.

Third, new market entrants provide innovative services such as consumer demand-side management programs. Just recently, on October 12, 2007, PJM reported that its most recent forward capacity market auction, which helps ensure reliability by providing capacity resources when they are most needed, netted 963 MW of consumer demand response, the equivalent size of a large power plant.[5] And in one of the hottest weeks in August 2006, PJM estimated that demand response resources provided $650 million in reduced costs.[6] Notably, these savings were realized when they were most valuable: during times of peak demand. Such robust demand response is a direct result of wholesale markets beginning to express true market price signals and supporting

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http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2006-som-volume-i.pdf

4 A brief overview of PJM is available on the PJM website: http://www.pjm.com/about/overview.html.

5 See, "PJM RELIABILITY PRICING MODEL ATTRACTS MORE GENERATION, DEMAND RESPONSE, Press Release, October 16, 2007, http://www.pjm.com/contributions/news-releases/2007/20071012-RPM-auction-results1.pdf.

6 See, "EARLY AUG. DEMAND RESPONSE PRODUCES $650 MILLION SAVINGS IN PJM," Press Release, August 17, 2006 Available at: http://www.pjm.com/contributions/news-releases/2006/20060817-demand-response-savings.pdf

innovative approaches to facilitate customers' usage reduction when it is most valuable. PJM projects that still more consumer demand response resources will be bid into the capacity market auction, providing even greater savings for all electric customers.

Thus, despite some claims to the contrary, the 1996 Competition Act has provided, and will continue to provide, significant benefits. Of course, electric restructuring remains a work in progress, and more remains to be done. Moreover, there is no doubt that electricity has become substantially more expensive since the 1996 legislation passed. The expected price increases are a primary impetus for proposed changes impacting the Pennsylvania electric industry. Before embarking on any such reforms, however, it is critical to understand why electric prices increased.

WHY DID ELECTRIC PRICES INCREASE?

Increases in electric prices have been caused primarily by unprecedented increases in the prices of all fossil fuels. Natural gas prices, for example, more than tripled between 1999 and 2006, the result of significant increases in demand for natural gas.[7] Additionally, prices for coal burned in Pennsylvania's coal-fired plants increased by about 60 percent over that time period.[8] As coal sets the market price in PJM 70 percent of the time and natural gas 25 percent of the time, wholesale electricity market prices increased as well.[9]

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[7] Hurricanes Katrina and Rita also affected natural gas prices in the latter part of 2005 and into 2006 because of the damage done to natural gas gathering infrastructure along the Gulf Coast.

[8] See, "PJM Wholesale Electricity Markets Again Found Competitive," available at: http://www.pjm.com/contributions/news-releases/2007/20070308stateothemarket.pdf.

[9] 2006 SOM, at 11.

The PJM 2006 State of the Market Report indicates that average real-time energy prices decreased by over 15 percent in 2006 from their 2005 levels.[10] Even adjusting for the decrease in fuel prices between 2005 and 2006 (especially the decrease in natural gas prices), average prices fell over 5 percent.[11] This confirms that generators became more efficient and reduced their non-fuel operating costs, exactly the positive type of behavior competitive markets promote.

Furthermore, at the same time that fossil fuel prices were rapidly increasing, so was the demand for electricity. Between 1999 and 2005, electric consumption in Pennsylvania increased by over 10 percent. Both the effects of these large increases in fossil fuel prices and increased electric consumption caused wholesale market prices to rise. If not for competition and the efficiency gains such as those discussed above, electric prices would likely have increased even more. The strong market incentives to improve operating efficiency and plant performance, which have substantially reduced generating costs, would not exist. Moreover, Pennsylvania consumers would still bear all of the financial risks of construction cost overruns, poor operating performance, and forced plant outages, just as they did prior to restructuring.[12]

[10] Id.

[11] Id.

[12] Critics of restructuring fail to consider the costs of utilities building new generating resources and passing along unexpected construction cost increases. For example, Duke Energy announced that the construction costs of a new baseload coal plant in North Carolina had increased by 50%. See, In the Matter of Application of Duke Energy Carolinas LLC for Approval for an Electric Generation Certificate of Public Conveyance and Necessity to Construct Two State of the Art Coal Units for Cliffside Project, Docket No. E-7, Sub 790, Supplemental Testimony of William McCollum, Jr., November 29. 2006. This estimate does not include capitalized interest payments, which are expected to add another $400 million in cost to the plant.

MOVING FORWARD

Electric prices increased as a result of two basic economic forces: supply and demand. This single fact – that electric prices will rise after below market price caps expire – lies at the heart of the debate about the future of Pennsylvania's electric industry. Yet, policymakers must appreciate that they cannot prevent the effects of these most basic of market principles.

The 1996 Competition Act provided real benefits to Pennsylvania's electric consumers, but it also contributed to the situations facing us today. Although the multi-year price caps "locked-in" billions of dollars of benefits for consumers and insulated them from the ups and downs of competitive market prices over more than a decade, like all other price controls, they now expose consumers to the increases that inevitably occur when below-market price caps end.

But replacing a robust, competitive market with government regulation is not the solution to the challenge of increasing prices. Government mandated resource decisions, however well intentioned, have never worked. For example, California froze utilities' rates and did not allow them to recover their actual market costs. This drove one utility into bankruptcy, and another to the verge of bankruptcy, compelling the State to procure electricity on their behalf. The State signed numerous, long-term contracts, most at prices that turned out to be far above market, costing California consumers billions of dollars. In contrast, well-designed comprehensive transition plans that include staggered competitive procurements and budget and phase-in plans to smooth initial price increases will benefit consumers and are the far better solution.

COMPETITIVE PROCUREMENT PROGRAMS

Moving forward, a key issue will be how Pennsylvania consumers obtain their electric supplies. There has been much misinformation on this issue. For example, some advocates of a return to the previous regulatory system, have referenced a recent article by Marilyn Showalter that claims competition has cost Pennsylvania billions of dollars[13] and rates in restructured states such as Pennsylvania have risen much faster than in unrestructured states, such as Washington and Idaho. However, Showalter's simplistic rate "comparisons" and assertions are invalid.

As discussed previously, electric rates have increased substantially in both unrestructured and restructured states largely in response to increases in fuel costs. Thus, any meaningful comparison of rates in restructured vs. non-restructured states must control for the other important factors that drive price differences, as well as the rate of change of price differences. Differences among states' labor rates and in the fuel mix of their generation are among the most obvious and important factors that must be considered for any meaningful comparison.

Notably, a recently published study, which considered these critical factors and performed a similar comparative analysis as Showalter's came to the opposite conclusion.[14] The authors concluded that there was no significant difference in rate changes during 1997-2006 between restructured and non-restructured states with rates increasing by approximately 31% in both groups. Furthermore, those

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[13] See, e.g., M. Showalter, "A Billion Here, A Billion There: Price Matters." Available at: http://ppiforum.wordpress.com/2007/08/06/a-billion-here-a-billion-there-price-matters.

[14] J.P. Pfeifenberger, G.N. Basheda, and A.C. Schumacher, "Restructuring Revisited," *Public Utilities Fortnightly*, June 2007.

authors concluded that the rate increases in the restructured states "lagged" the rate increases in the unrestructured states, resulting in a $24 billion *benefit* to customers in restructured states through 2006.

Competitive procurements have been successfully conducted in several states, including Maryland and New Jersey. Yes, prices increased; not, however, because of deregulation, but in response to underlying supply and demand conditions. Arguing that competitive market prices are "too high" implies that government-run, regulatory approaches can somehow "beat the market." A far better response is to rely on the power of a robust market, which, as PJM's October 12th announcement about demand response resources shows, will incent new and innovative offerings and programs.

Competitive procurement helps ensure reliable, reasonably priced electricity. Head-to-head competition through open, transparent procurement such as auctions and requests – for – proposals will produce the lowest available price. Furthermore, such procurements can be structured to smooth out any transitional price increase by establishing overlapping supply contracts and contracts of varying durations.

Finally, such workable competitive procurement programs can be linked with well-designed transition programs to mitigate the adverse impacts of sudden price increases. These transition programs can include phasing out rate cap increases over several years to smooth the transition to market-based rates.

CONCLUSIONS

Electric industry restructuring has provided real and measurable benefits to Pennsylvania consumers and businesses. Consumers no longer bear the financial risks of failed generating plants or cost overruns, as they did under the old regulatory system. And innovative providers of energy conservation and consumer demand response resources are growing rapidly.

There are no "silver bullets" policymakers can use to prevent an increase in electric prices. Neither regulation nor competition can prevent the tremendous increases in worldwide demand for fossil fuels that have driven electric prices higher. But, unlike more regulation, competition can provide the lowest available cost.

Government policies can establish a framework that fosters competition, addresses environmental realities, and encourages more efficient use of resources. Government policies can also provide resource diversity by ensuring that consumers are exposed to correct market signals, which will facilitate development of new generation and transmission infrastructure, and will promote consumer demand response. The reality is that no amount of government intervention, however well intentioned, can change the basic principles of supply and demand. The best approach is to apply those market forces to create an even more robust, competitive market for Pennsylvania's electricity consumers to ensure the lowest available price.

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Retail Electric Competition in New York: Benefits for the Present, Promise for the Future

An Examination of Progress of Electric Market Restructuring in New York State, 1995-Present

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Capitol Hill Research Center White Paper

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EXECUTIVE SUMMARY

The purpose of this White Paper is to assess the impact that retail electric competition has had in New York State. Based both on qualitative and quantitative analyses, the inescapable and irrefutable conclusion is that for consumers who have chosen competitive suppliers, the following benefits have resulted:

- increased supply choices through value-added products and services;
- downward pressure on prices;
- enhanced price transparency for all consumers, especially residential consumers;
- environmental improvements through energy efficiency and demand response; and
- reduced stranded costs for ratepayers.

By all measurements, where the New York Public Service Commission ("PSC") has implemented a retail electric market structure that enables customers to know their true costs of consumption through market-reflective price signals and enables competitive energy service companies (ESCOs) to use this information to develop a variety of product offerings tailored specifically to the customer's needs, the benefits of retail electric competition set forth above have been realized.

New York State is widely viewed as a national leader in bringing the benefits of a robust and sustainable retail electric market structure to its citizenry and businesses. In fact, the recently released *Report To Congress on Competition in Wholesale and Retail Markets for Electric Energy*[1] created by a task force (Task Force) comprised of the Federal Energy Regulatory Commission (FERC), and four other federal governmental agencies, stated that the promise of retail competition has come true and has provided lower prices for commercial and industrial consumers, and in the cases of New York, Texas and Massachusetts has also come true to varying degrees for residential customers. New York has one of the most active and competitive retail energy markets in the nation with more than 75 ESCOs providing an array of innovative, value-added services tailored to meet the customer's specific needs and requirements. In addition, data compiled by the Energy Information Administration (EIA) indicates that electricity prices have actually declined in real terms since the PSC initiated retail competition.[2] Furthermore, customer migration to competitive commodity supply options has grown exponentially, with switching activity increasing significantly in 2006 in all market sectors – residential, small commercial and large commercial and industrial.

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[1] *See* The Electric Energy Market Competition Task Force, *Report To Congress on Competition in Wholesale and Retail Energy Markets For Electric Energy*, (April 6, 2007), hereinafter referred to as the Federal Competition Report. The Energy Policy Act of 2005 required the Task Force to conduct a study and analysis of competition within the wholesale and retail market for electric energy in the United States and to submit a report to the United States Congress. The five-member Task Force, comprised of representatives from the Departments of Justice, Energy and Agriculture, and the Federal Energy Regulatory Commission and the Federal Trade Commission, consulted with and solicited comments from the States, representatives of the electric power industry and the public.

[2] Information can be found at the EIA website;
http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls

The White Paper will clearly demonstrate that the documented benefits of retail energy markets in New York State should dispel any misperceptions surrounding the price of electricity since 1996, availability of wide ranging energy product and service choices, and customer switching. First, electricity prices in real dollar terms (inflation adjusted) have declined since 1996. Second, where the PSC has permitted the correct retail electric market structure to be implemented, customer choices abound for every market segment with ample choices of competitive suppliers and supply products. Finally, the rate of customer migration has varied greatly depending on the specific electric restructuring program design that was adopted by the local electric distribution utilities. It is not surprising that the utilities that have embraced competitive markets and have adopted market rules that facilitate customer choice have experienced the greater amount of customer switching, expressed in terms of customer accounts and megawatt-hours. Conversely, those utilities that have created artificial shopping and enrollment periods, along with market rules that have oftentimes confused ratepayers in their service territories, have experienced limited customer switching.

It is a virtuous circle that competitive choice creates and, for the energy market, the benefits are enormous. Competition not only brings downward pressure on prices, but also improved service, new technologies, new service orientations and new organizations.[3] Nowhere are the benefits greater than for the business sector, where energy costs have consistently ranked among the most important considerations for small business, along with health insurance costs and state and local taxes,[4] and direct links have been demonstrated between those costs and job growth.[5] Furthermore, with the ability to integrate energy efficiency and demand response measures into their electricity supply strategies, customers have an even greater ability to manage their energy costs and further benefit from competitive markets. Efficiency and demand reduction are concepts that were inherently at odds with the cost-of-service utility ratemaking model, but can thrive in a competitive market not driven by throughput but rather creativity and product innovation.

The public policy implications for New York State are quite clear. The Spitzer Administration has outlined a number of specific energy and related goals since it took office at the beginning of the year. Among those goals are lower energy costs, developing new and cleaner energy technologies, and economic revitalization through the reduction of the cost burden for the State's businesses. Given the success of electric restructuring – thus far, and the promise it holds for the future, the competitive energy

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[3] Isser, S, et al. (1998). "Enron's battle with PECO: an inside view from outside the industry," in *Public Utilities Fortnightly.* March 1, 1998 v136 n5 p38(6)

[4] National Federation of Small Businesses (2005). "Small Firms' view of New York economy continues to sour: energy costs now rank with insurance as top business headache," at http://www.nfib.com/object/sbcny1205.html. Other surveys by NFIB show similar concerns about energy prices in other states.

[5] *The Impact of Increased Energy Costs on Businesses and Jobs* (2006). Prepared by Management Information Services, Inc., for Americans for Balanced Energy Choices. November 2006. Available at http://www.balancedenergy.org

market is one of the most dynamic and effective tools the Administration has for achieving its goals.[6]

GOALS OF THE SPITZER ADMINISTRATION

In his State of the State Address, Governor Spitzer dedicated considerable time to the task of economic revitalization, noting that

> "...we must reduce New York's cost structure – the "perfect storm of unaffordability" – for both businesses and people... As the world has transformed and moved forward, it is only Albany that has stood still. As the economy becomes global, and reveals our competitive disadvantages, we must reduce the burdensome cost structures that have driven businesses out of our state."[7]

While the Governor was referring more specifically to the costs of health insurance, workers compensation and property taxes, energy costs – which he identified as second highest in the country – are also a part of that burden.

In a speech last January to the New York State Energy Association, Lieutenant Governor David Paterson summed the goals of the Spitzer Administration's energy policy into three key components - development of reliable energy infrastructure, driving down electric service cost, and maintaining good stewardship of the environment through conservation and the development of renewable energy. If New York is going to move forward, the Lieutenant Governor said,

> "...we must provide a reliable infrastructure which can meet the increase in demand from its citizens and increase our economy. We must act now to improve our energy system. To accomplish this, we have to change our attitude about energy."[8]

In a recent speech to the Saratoga Chamber of Commerce, the leader of the Business Council of New York State cited the reduction of energy costs as one of the three key elements to reviving the upstate economy.[9]

There is no better way to achieve the goals of the Spitzer Administration than through robust, vigorous competition, where regulatory oversight is to effectuate these aims, not restrict the methods by which to achieve them. To be sure, the Administration has

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[6] It should be noted that while this paper is focused primarily on the ratepayer benefits of retail electric competition in the State of New York, wholesale and retail competition are inextricably connected. In other words, a healthy and robust competitive retail electric market depends on a properly functioning wholesale electric market.

[7] *State of the State Address* (2007), available at http://www.ny.gov/governor/keydocs/2007sos_speech.html; See also: Speech by Eliot Spitzer to the New York Association of Counties, January 30, 2007. http://www.state.ny.us/governor/keydocs/0130071_speech.html

[8] Speech to Energy Association Breakfast, 1/17/07; available at http://www.ny.gov/governor/keydocs/0117071_dapspeech.html

[9] Andersen, E. (2007). "Business Council head offers vision for upstate: Ken Adams says reforming workers' compensation is one of several ways to revive the economy," in *Times Union* (Albany). 3/16/07.

embraced the virtues of competition in other public policy areas. In the opening days of his new administration, the Governor called for greater choice, competition and accountability in education policy in New York. Calling for a break from the existing public education paradigm, the Governor has embraced the concept of competition for the state's public schools. In his Executive Budget, he proposed raising the charter school cap to help demonstrate educational innovations that work, and make other schools compete. Charter schools make other public schools compete, the Governor argued, which is why many strong school administrators welcome their presence.

> "We can choose a past of high property taxes, poor performance, and morally indefensible inequality - or a future of knowledge, opportunity and hope. I have already made my choice. Together I know we will redefine the future of New York."[10]

This recognition that competitive choice is the best way to produce the highest service for all New Yorkers should not be reserved only for the field of public education. The argument applies equally well to the energy sector.

As discussed herein, energy restructuring in New York has proven successful where the correct retail market design has been permitted to develop. It also holds out the greatest promise for the Spitzer Administration to achieve its goals. At a time when New York must strive to remain economically competitive in terms of the retention and attraction of jobs and businesses into the state, the Administration should look to policies designed to encourage the continued develop of retail energy market structures that will benefit all New Yorkers.

ELECTRIC RESTRUCTURING IN NEW YORK STATE

For most of the twentieth century, the electricity industry operated under a classic monopolistic market structure whereby one utility firm received the "franchise rights" to produce, deliver and sell the entire load for a particular market area. By the mid-eighties, however, that perception was increasingly challenged by economists and policy-makers. Between 1974 and 1984, the average price of electricity in the United States increased by approximately 250 percent, an increase that attracted the attention of consumers and politicians alike.[11] Attempts by the industry to address these problems often resulted in poor investment decisions, most notably in nuclear power plant construction.

- In 1965, when the Long Island Lighting Company (LILCO) first announced its intention to build a nuclear plant in Suffolk County, elected officials fervently embraced the project. Within a year, LILCO acquired a 455-acre site between the sparsely populated hamlets of Shoreham and Wading River, and declared that its new plant would be on line by 1973, at a cost of $65 million-$75 million. By the time Shoreham was fully decommissioned on Oct. 12, 1994, it cost nearly $6 billion - about 85 times higher than the original estimate – and destroyed LILCO. The intervening years were marked by astonishingly low worker productivity, design

[10] Available at http://www.state.ny.us/governor/keydocs/0129071_speech.html
[11] Pierce, Jr., R.J. (2005). "Completing the Process of Restructuring the Electricity Market," in *Wake Forest Law Review*. V.40, No.2, Summer 2005.

changes ordered by federal regulators, and extensive battles over evacuation plans. Though Shoreham never produced a kilowatt of commercial power, the agreement that shuttered the plant forever made ratepayers responsible for most of Shoreham's cost, saddling Long Island with some of the highest electric rates in the nation.[12]

- In 1972, the Public Service Company of New Hampshire (PSNH), applied for permission as a principal investor to build a two-unit nuclear plant at Seabrook, New Hampshire with a projected cost of $900 million. Construction began in 1976, with an expected opening date in 1985. In 1979, the State of New Hampshire barred PSNH from passing the rising costs of construction on to ratepayers until the plant began operating. By 1983, the projected cost estimate spiraled to $5.2 billion; when the cost rose to between $9 billion and $10 billion in 1984, one of the reactors was canceled and construction was halted after banks cut off the utility's credit. By 1988, with the cost of the single-reactor plant at $5.2 billion, PSNH became the first utility in the United States to file for bankruptcy protection since the Great Depression.[13]

As a result of rising costs and such high profile, colossal investment failures by industry, the existing paradigm of natural, regulated monopoly came under fire.

Competition entered wholesale markets with the passage of the 1978 Public Utility Regulatory Policy Act (PURPA). PURPA established a new class of "unregulated" generators termed Qualifying Facilities, which could sell power to regulated utilities and be paid for the avoided costs of those utilities. Continuing on the success of PURPA, in 1992, Congress further opened the $220 billion electricity industry to competition with the National Energy Policy Act, which allowed an even broader group of competitive power producers to compete for the sale of electricity to utilities. Four years later, FERC issued Order No. 888, which required utilities to "remove impediments to competition in wholesale trade and to bring more efficient, lower cost power to the nation's electricity customers."[14] The requirement that electric transmission lines be accessible for all producers facilitated the states' restructuring of the electric power industry to allow customers direct access to retail power generation, and several states launched pilot programs allowing competition shortly thereafter.

Restructuring must be looked upon as an evolutionary process, through which an industry must go from a heavily regulated and static environment in which utility profit margins are virtually assured to one driven by dynamic market-based competitive forces. Transition between the two in any industry is highly complex and difficult in part

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[12] Fagin, D. "Lights out at Shoreham: anti-nuclear activism spurs the closing of a new $6 billion plant." Copyright 2007 by Newsday, Inc., available at http://www.newsday.com/community/guide/lihistory/ny-history-hs9shore,0,563942.story

[13] *Newsday* (1988). "Chapter 11 for NH Utility: Seabrook debts force filing for bankruptcy protection." 1/29/88.

[14] Federal Energy Regulatory Commission. *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*. Order No. 888, Final Rule; Summary p.1. Issued April 24, 1996. Available at http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00v.txt

because of the differing political and economic structures of a regulated industry versus a competitive one. In the former, important organizational decisions (e.g. pricing, profits, entry and exit and terms of doing business) are conducted largely by public officials, or regulators. The culture is monopolistic, and the role of the regulator is to assure reliability and reasonable energy prices for customers, while also providing a rate of return for shareholders. By contrast, the culture of the competitive industry is entrepreneurial, in which private shareholders make decisions and those decisions are made within the context of consumer satisfaction with regard to quality, innovative new products and services and price.[15] From the outset, the key challenge has been to expand competition in the supply of retail electricity services in a way that preserves operating and investment efficiencies, but mitigates the price increases associated with the old regulated model.[16]

Restructuring must be looked upon as an evolutionary process, through which an industry must go from a heavily regulated and static environment in which utility profit margins are virtually assured to one driven by dynamic market-based competitive forces.

In New York, the entity charged with guiding the industry through the transition phase has been the PSC. The PSC began restructuring of the State's electric industry in the mid-1990s to promote efficient energy services at just and reasonable rates while providing customers with greater choice, value and innovation.[17] In so doing, the PSC set forth its expectations that competition was expected to produce downward pressure on prices, offer consumers new supply pricing options and services and provide more value-added services such as heating system and appliance maintenance and energy efficiency consulting.[18] This unleashing of greater choice and innovation, the PSC postulated, would produce for New York's consumers better value for their energy dollars.[19]

Rather than impose a specific one-size-fits-all solution for electric restructuring across all of New York's electric distribution utility service territories, the PSC developed a comprehensive policy framework and worked with industry participants in each of New York's utility service territories to implement policy goals on a utility-by-utility basis. In 2004, the PSC issued its *Statement of Policy on Further Steps Toward Competition in Retail Energy Markets* ("Policy Statement").[20] In this Policy Statement, the PSC identified important steps to accelerate the development of retail competition in New York's electric markets, including the submission of retail access plans by each electric distribution utility and the implementation of "best practices" for fostering the

[15] Foer, Albert A. (2002). "Electricity: Notes of the Transition Phase," *Loyola University Chicago Law Journal.* V. 33, Summer 2002.
[16] Joskow, P.L. (1997). "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," in *The Journal of Economic Perspectives*. V.11, No.3, Summer 1997.
[17] New York Public Service Commission, *Staff Report on the State of Competitive Energy Markets: Progress To Date And Future Opportunities* (March 3, 2006), hereinafter "PSC Staff Competition Report" p. 29.
[18] *Id.*
[19] *Id.*
[20] New York Public Service Commission Case No. 00-M-0504, *Statement of Policy on Further Steps Toward Competition in Retail Energy Markets* (Aug. 25, 2004).

availability of competitive choices for customers. These "best practices" included: ESCO referral programs, utility purchase of ESCO receivables, and the use of hourly-priced default service for large commercial and industrial customers. Many of the "best practices" identified in the PSC's Policy Statement were implemented by subsequent PSC orders in 2005 and 2006.

Now, as a combination of rising fuel costs and tightening supply have placed upward pressure on the nominal price of energy everywhere, some advocacy groups and a number of elected officials in New York are publicly questioning whether the expected benefits of restructuring will ever be realized. Looking at nominal prices in New York since deregulation began, some parties have argued that New York's consumers have not experienced the anticipated benefits of market-driven competition. Despite this perception, the average price of power in ***real dollar terms*** has in fact ***declined*** in those states that have restructured their markets, including New York, over the era of deregulation from 1997 to 2006. This gap between the perception perpetuated by retail competition's opponents and reality suggests that power price trends are widely misunderstood, a misunderstanding that can lead to public misinformation and, more importantly, poor decision-making.[21]

Although some parties, focusing on the need for additional energy infrastructure, have suggested that New York's utilities should enter into long-term procurement contracts with new generation, there could be detrimental consequences of such a drastic change in course. Not only could such an action seriously distort retail prices, thereby harming the current robust and sustainable retail market structures already implemented for medium-sized and large commercial and industrial ("C&I") customers in New York, it would also dramatically impact that progressive market development for residential and small mass-market commercial customers who are only beginning to enjoy the benefits of retail electric competition. Moreover, such a singular focus on this design as a panacea for New York's generation woes creates the real concerns that: (1) long-term contracts will deter market based solutions; and (2) in the meantime, the retail market that has worked so well for large C&I customers and holds great potential for smaller customers, will have been destroyed. This is the one policy scenario that the Spitzer Administration should work diligently to avoid.

THE SUCCESSES OF NEW YORK'S ENERGY RESTRUCTURING POLICIES

It has now been a decade since the PSC embarked on the process to restructure of New York's energy markets. Therefore, it is timely and appropriate to evaluate its success at this stage of market development. The following analysis will examine how restructuring has progressed in New York since 1996. In doing so, it will demonstrate the success of restructuring of energy markets. It produces two compelling conclusions: (1) the

[21] Cambridge Energy Research Associates (CERA). *Beyond the Crossroads: The Future Direction of Power Industry Restructuring.*

competitive market is still evolving and needs continual evolution to achieve the Administration's goals; and (2) now is not the time to retreat to the regimented model of the past that failed to place downward pressure on consumer prices or increase the quality of customer service.

The evidence shows that although the transition to restructured energy markets in New York is incomplete, for sectors where the market is structured to allow for robust and sustainable retail competition, numerous competitive ESCOs have entered these markets and have invested in and provided needed infrastructure and customer-oriented products and services tailored to the customer's specific needs. The role and impact that ESCOs have played and continue to play in the development of the retail market cannot be understated. The choices that ESCOs are offering retail customers, regarding - the varying of pricing and service products, are meeting the goals of placing downward pressure on prices, increased efficiency, improved and advanced technology and environmental protection far more effectively than the regulated monopoly utilities can.

The success of New York's restructuring policies can be seen in the benefits they have brought to consumers:

- increased choice through value-added products and services and increased efficiency;
- downward pressure on prices; and
- environmental protection through conservation and demand response product offerings.

It must be noted at the outset that the extent to which this success has occurred is in large part a product of the retail market structure that has been permitted to develop in New York. In this regard, the Federal Competition Report is particularly instructive in its examination into whether retail competition in several states was meeting the goals of:

- lower electricity prices than under traditional cost of service regulation;
- better service and more options for customers;
- technological innovation and new products and services for consumers; and
- environmental improvements.[22]

The Task Force concluded that retail competition met these goals only where the appropriate retail market structure was implemented and permitted to take hold.[23] In examining the status of retail competition of several states, including New York, the Task Force found that New York had developed a robust and sustainable retail market structure for commercial and industrial customers and, unlike most other states, had facilitated a structure to enable some residential customers to participate in and benefit from retail markets.[24]

This begs the question as to what is the appropriate retail market structure that unlocks for customers the benefits of a robust and sustainable competitive retail market structure. That structure is one where customers are able to receive a price signal that enables them

[22] Supra note 1, p. 6.
[23] Supra note 1, pp. 84-108.
[24] Supra note 1, pp. 6-7, 106-107.

to see their true costs of energy consumption and use this information to obtain the energy supply product that is best tailored to their own specified consumption needs. This price signal is conveyed best when the default service price – that is, the price customers would receive if they remained with the incumbent New York utility on default service rather than receive competitive service from an ESCO – is as close to market-reflective as practicable. With this price signal, customers can shop for and ESCOs can compete against one another to innovate and produce product offerings that are tailored to the customer's specific needs.

This retail market structure has been implemented for large commercial and industrial customers through the Commission's implementation of mandatory hourly-priced default service in 2006, and as a result these customers have seen the benefits of restructuring detailed in this analysis. In addition, smaller customers have experienced the benefits of retail competition, albeit to a lesser degree, as the Commission has implemented default service that partially relies on market-reflective default service prices as part of a portfolio mix with short-term and medium-term prices that are the product of hedging arrangements between the New York utilities and wholesale suppliers. However, because the Commission has prevented smaller customers from receiving clearer price signals, the benefits of retail competition have been slower to come for these customers, as evidenced by the fact that New York, despite all of the benefits already generated to date by retail competition, remains in a transition to restructuring especially for smaller customers.

Despite the conservative pace of restructuring for these residential and smaller commercial customer sectors, an examination of the current situation demonstrates that the expectations of retail electric restructuring are being met. Competition can be counted on to deliver much more dramatic customer, economic and environmental benefits as public policy allows the market structure to continue to mature.

Increased Consumer Choice

Even though the competitive retail markets are still evolving, one recent survey found New York to not only be a national leader with regard to electric choice but also a market poised for significant growth in the residential customers sector due in large part to operational improvements and Commission programs such as ESCO referrals and Purchase of Receivables ("POR").[25] Clearly great strides have been made that provide a glimpse of the increased benefits as the market structure evolves to allow for more vigorous competition. The PSC's commitment to "retail access plans" – programs that make it easier for residential and small businesses to shop for power and understand choice – has revolutionized how small businesses are able to compare prices and test the market.

Increased consumer choice can be measured in three ways: the number of Energy Service Companies serving consumers; new technologies that provide environmentally clean energy alternatives and/or encourage energy efficiency and consumer conservation; and

[25] *See* KEMA 2006 Restructuring Review, pp. 1-5, 1-19, 1-32 and 2-126 through 2-137

migration rates of consumers from their default choice of the utility company to an Energy Service Company.

Energy Service Companies

An Energy Service Company (ESCO) is a non-utility business that primarily provides gas or electric commodity and/or installs energy efficient and other demand-side management measures in homes and businesses. ESCOs play a leading role in the PSC's vision of deregulation as independent energy suppliers while utilities are still regulated for the transmission and delivery of the commodity to the consumer. The ESCO community is comprised of power aggregators, marketers and brokers, who meet the requirements of and are monitored by the PSC and subject to the business laws of the State of New York. Where allowed, they are able to offer specifically tailored products – based on physical and financial instruments designed to match their customers' needs as buyers with the wholesale market as sellers – to suit the needs of particular customers.

ESCO participation has increased significantly, with nearly a third more ESCOs providing service to New York consumers by the end of 2005 than there were in 2003. There are currently about 100 approved ESCOs in New York, with 75 providing gas and/or electricity service to customers.[26] Indeed, for residential customers, Texas and New York are the two states in which more than just a handful of suppliers serve residential customers. In Texas, residential customers have approximately 15 suppliers from which to choose.[27] At least 7 ESCOs are serving residential electric customers and at least 14 are serving non-residential electric customers in each major New York utility service area.[28]

As anticipated, ESCOs provide an array of innovative value-added services tailored to meet customers' needs. This allows ESCOs to distinguish themselves in ways other than price, and leads to the greater benefits for consumers and society as a whole than monopoly-based service. Many consumers are influenced in their choice by price; however in competitive markets choices other than price are also sought by consumers. Many consumers are willing to pay more for a product if they know their supplier is buying renewable energy and not contributing to the burning of fossil fuels. Other consumers look for a company that best models the corporate behavior they desire. Products such as load control, energy efficiency assistance, and telephone service are bundled with energy. In several service territories, ESCOs are separately offering optional home furnace cleaning and maintenance contracts and at least one ESCO offers this service bundled with its natural gas commodity. Others offer fixed pricing, which allows customers to lock into a fixed price for an extended period of time, or flexible

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[26] See *Governing Competitive Governing Competitive Retail Energy Markets Retail Energy Markets --A New York Status Report.* Illinois Commerce Commission Electric Policy Meeting Chicago, IL. October 2, 2006, at http://www.icc.illinois.gov/docs/tc/061002tcCompCerniglia.pdf.

[27] Texas Public Utilities Commission, *Texas Electric Choice Compare Offers from Your Local Electric Providers*, available at http://www.powertochoose.org/default.asp, cited in *Report to Congress on Competition in the Wholesale and Retail Markets for Electric Energy*, by The Electric Energy Market Competition Task Force, June 5, 2006. p.80.

[28] PSC Staff Competition Report, p.38.

pricing that is driven by short-term fluctuations in the market price, depending on how risk averse or tolerant the consumer chooses to be.[29]

Innovation

Nowhere are the potential benefits of competition greater than in the development of new technologies that will provide consumers with the tools they need to make rational choices in their energy use:

Combined Heat and Power

Combined heat and power (CHP), also known as co-generation, is an efficient, clean, and reliable approach to generating power and thermal energy from a single fuel source. CHP is not a specific technology but an application of technologies to meet an energy user's needs. CHP systems achieve typical effective electric efficiencies of 50% to 70% — a dramatic improvement over the average efficiency of separate heat and power. Since CHP is highly efficient, it reduces traditional air pollutants and carbon dioxide, the leading greenhouse gas associated with climate change, as well.[30]

- Employees on the shop floor of Harbec Plastics Inc., an injection molding company in Ontario, New York, suffered in temperatures above 100 degrees Fahrenheit during the summer months. Since the provision of air conditioning using electricity from the grid was cost prohibitive, an alternate solution had to be found that would provide cooling in an economically viable and environment-friendly way. Harbec installed a 250 kilowatt (kW) wind turbine and twenty-five micro-turbines (combined heat and power) which generate electricity and provide the heating and cooling needs for the plant.

  The project saves the company $165,000 per year in energy costs and reduced carbon dioxide emissions by 90 percent due to use of renewable and alternate energy sources. Harbec is able to predict 20 percent of electricity needs at least 25 years into the future, and has the option of using alternative renewable fuels (e.g. bio-diesel, hydrogen) to run the micro-turbines.[31]

Thermal Storage

Thermal storage is an ice storage based air-conditioning system that shifts the electrical load from daytime to nighttime when electricity is more plentiful, less expensive and generated more efficiently. In addition, the technology reduces consumption and demand via a more efficient low flow/low temp chilled water operation, and facilitates the transition between free cooling and mechanical cooling. Thermal storage systems have been recognized for improving the reliability of the electric grid by permanently shifting peak cooling loads from on-peak to off-peak.

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[29] Supra note 17, p.40.

[30] For more on CHP, see the Environmental Protection Agency website at http://www.epa.gov/chp/what_is_chp.htm

[31] See the Center for Environmental Information at http://www.ceinfo.org/rgbn/details.php?CaseStudyID=1

- In 2006, Credit Suisse, a leading global investment banking and financial services firm, installed New York City's largest thermal storage based air-conditioning system at its City headquarters, which delivers dramatic energy savings. New York State Energy Research and Development Authority (NYSERDA) officials praised company officials for their commitment to energy efficiency and the environment. The system will greatly lower the facility's peak energy usage and overall electric while delivering improved site resiliency. In addition saving energy, the environmental benefits from this thermal storage system are equivalent to taking 223 cars off the streets or planting 1.9 million acres of trees to absorb the carbon dioxide caused by electrical usage for one year.

- The same year, Morgan Stanley also installed a similar system at its facility in Purchase, New York. Environmental benefits for that system are equivalent to the company planting 1.5 million acres of trees or removing 271 cars from Westchester County roads each year.[32]

Advanced Metering

The term "Advanced Metering" is used to mean an electronic meter that not only has the ability to read and store consumption information at predetermined intervals, but can also transmit this information electronically. Advanced Metering allows for automated meter reading (AMR), which eliminates the need for site visits by utility personnel. This not only saves money by the utility, it also provides the opportunity to implement time of use rates, and provides signals to customers who can then modify their energy-use behavior.[33] Many large C&I customers have advanced meters. By having access to their consumption information these customers have been able to take control of their energy use. ESCOs can obtain access to this data and develop products designed to meet the specific consumption needs of these customers.

In Texas, at least one utility has announced plans to install advanced meters in residential homes. With this announcement, retail suppliers in Texas are now developing products aimed at maximizing this new level of information about residential consumption. As the retail competitive market for residential and small commercial customers develops, similar types of product offerings are likely to develop for these customers.

[32] "Credit Suisse Recognized by New York State and New York City for Energy Conservation," (12/31/06) and "Morgan Stanley uses innovative ice storage system to reduce its electricity use." (6/27/06). Press releases from New York State Energy Research and Development Authority.

[33] New York State is also furthering the use of advanced meters through NYSERDA's Residential Comprehensive Energy Management Services Program (CEM). This program provides incentives to help fund a portion of the cost of installing advanced metering and energy management systems in both single-family dwellings and multifamily buildings. While this program is targeted at the residential sector in total, to date there are eight low income buildings representing 905 units participating in the program.

Real Time Pricing

Real Time Pricing (RTP) is the instantaneous pricing of electricity based on the cost of the electricity at the time it is used by the customer. RTP rates can vary over a wide range and are typically very high when system demand is high (e.g., on a hot, summer, weekday afternoon), and very low when system demand is low. Real-time rates differ from time-of-use rates in that they are based on actual (rather than forecasted) prices that may fluctuate frequently during a day and are weather-sensitive rather than varying with a set schedule. RTP is, in essence, market-reflective pricing that forms the building block for a retail market structure that can produce the benefits sought by the PSC in restructuring New York's electric industry because it sends the most accurate price signal to customers enabling them to make rational decisions about they way they use energy.

RTP adoption improves efficiency, reduces the variance and average of wholesale prices, and reduces all retail rates.[34] Real-time rates have been shown to reduce demand and wholesale prices during peak hours and increase demand and prices during off-peak hours, even when the amount of electricity involved is relatively small.[35]

The largest consumers in New York receive real time prices and these customers have benefited from a robust competitive market and myriad of product and service offerings to meet their needs. As more customers receive market-reflective price signals, they too will be better able to manage their electricity consumption by choosing the products that best meet their needs.[36]

Consumer Migration

The availability of choice has proved successful. This includes not only a significant percentage of residential customers, but many commercial and industrial customers as well.[37] Nationally, the migration of residential customers switching from the traditional service to an alternative competitive supplier is the greatest in those territories with more competitive suppliers.[38]

In New York, consumer migration rates have increased dramatically in the past two years, demonstrating that consumers are recognizing the benefits of choosing their energy supplier. As of December 2006, the total number of customer accounts who have migrated to a non-utility, alternative supplier was 1,236,617 - 752,092 electric customers, or 11.6% of the total eligible accounts, and 461,335 gas customers, or about 10% (Chart 1).[39]

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[34] Holland, P. and Mansur, E. (2005). *The Distributional and Environmental Effects of Time-Varying Prices in Competitive Electricity Markets*. University of California Energy Institute, Center for the Study of Energy Markets. 5/17/05. Available at http://repositories.cdlib.org/ucei/csem/CSEMWP-143/

[35] Center for Energy, Economic and Environmental Policy (2005). *Assessment of Customer Response to Real Time Pricing: Task 2: Wholesale Market Modeling of New Jersey and PJM.* Edward J. Bloustein School of Planning and Public Policy, Rutgers University. 11/11/05.

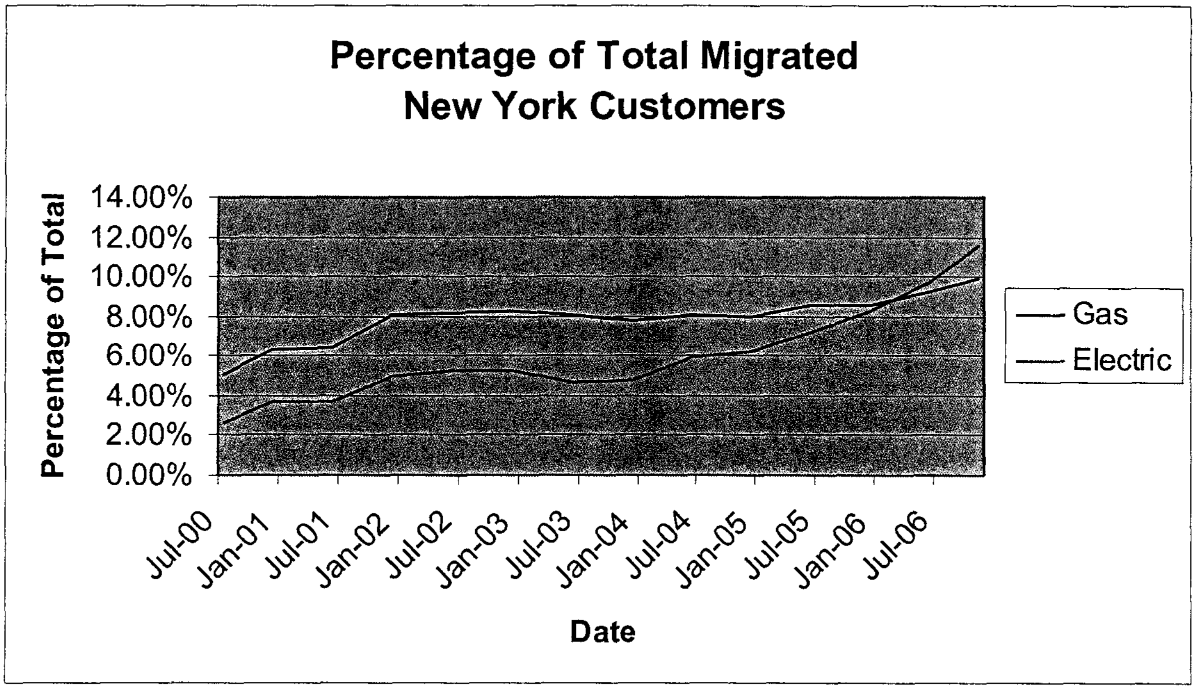
[36] See McKinsey & Company (2001). *The Benefits of Demand-Side Management and Dynamic Pricing Programs*. 5/1/01.

[37] Supra, note 22.

[38] Federal Competition Report, pp. 93-95.

[39] New York State Public Service Commission at http://www.energyguide.com/finder/NYFinder.asp?referrerid=209&sid=481

Chart 1



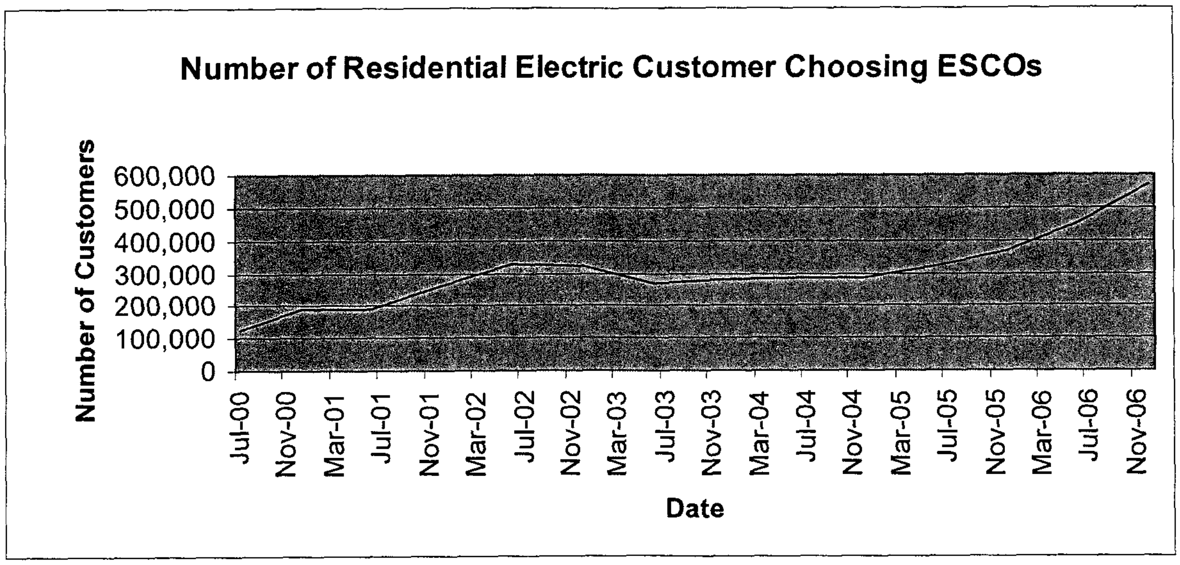
Source: New York Public Service Commission data

Evidence shows a significantly greater migration among industrial and commercial customers than among residential consumers. About 74% of the large commercial/ industrial, 49% of the small commercial, but only 11% of the residential load is being served by ESCOs.

Residential migration, however, has accelerated in the past two years. After reaching a high of 323,785 customers in June of 2002, the total number of residential customers dropped significantly over the next year, and did not recover completely until December of 2005. From a low of 264,534 in June of 2003 to December 2006, the number of residential customers who migrated to ESCO service has increased 95% (Chart 2). The Task Force has confirmed this finding in the Federal Competition Report, finding that "New York [has] more options for residential customers...[in part, because] between six and nine [competitive] suppliers offer services to residential customers in each service territory."[40] Furthermore, migration statistics have varied considerably depending on how much the local utility embraces competitive markets and whether they have adopted market rules that facilitate retail choice. For example, Orange and Rockland Utilities, Inc.,, which has been viewed as a proactive utility within New York for developing competitive retail energy markets, has achieved residential migration rates that are 2.5 and 3.8 times the state-wide averages for electric and gas customers respectively.

[40] Supra note 1, p. 94.

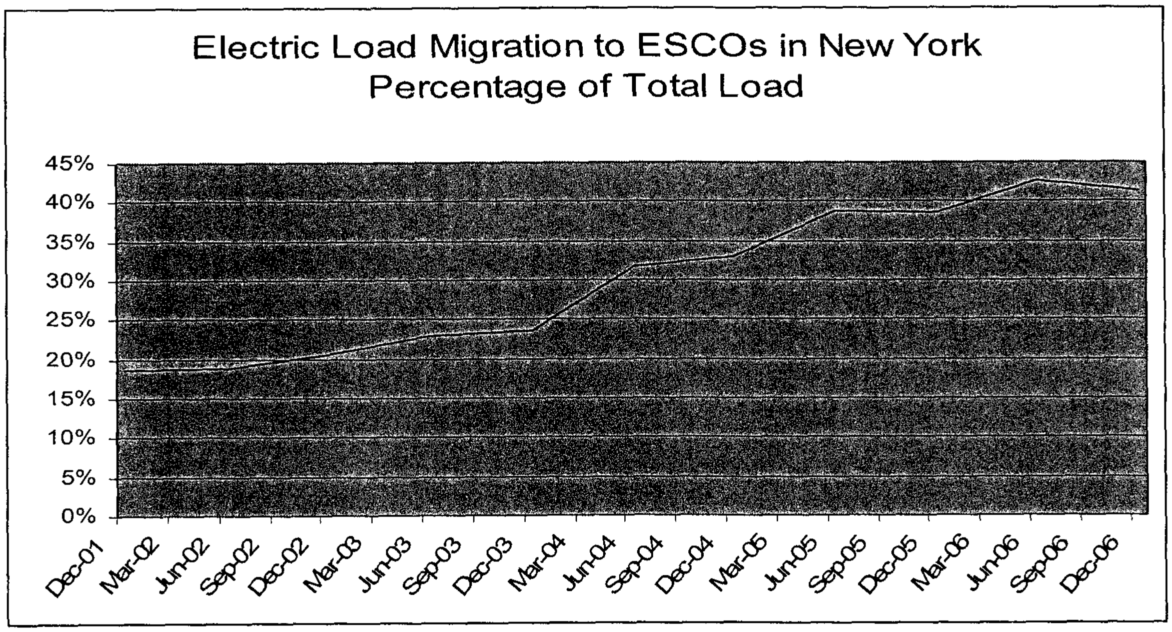
Chart 2



Source: NY Public Service Commission data

In the aggregate, 42% of all electricity used in the state is now being supplied through ESCOs, up from 19% at the end of 2001 (Chart 3).[41]

Chart 3



Source: New York State Public Service Commission

[41] November 8, 2006 Session of the PSC, minutes.

Downward Pressure on Prices

There are essentially three ways to test whether deregulation has been successful in applying downward pressure on prices, thereby keeping them in check:

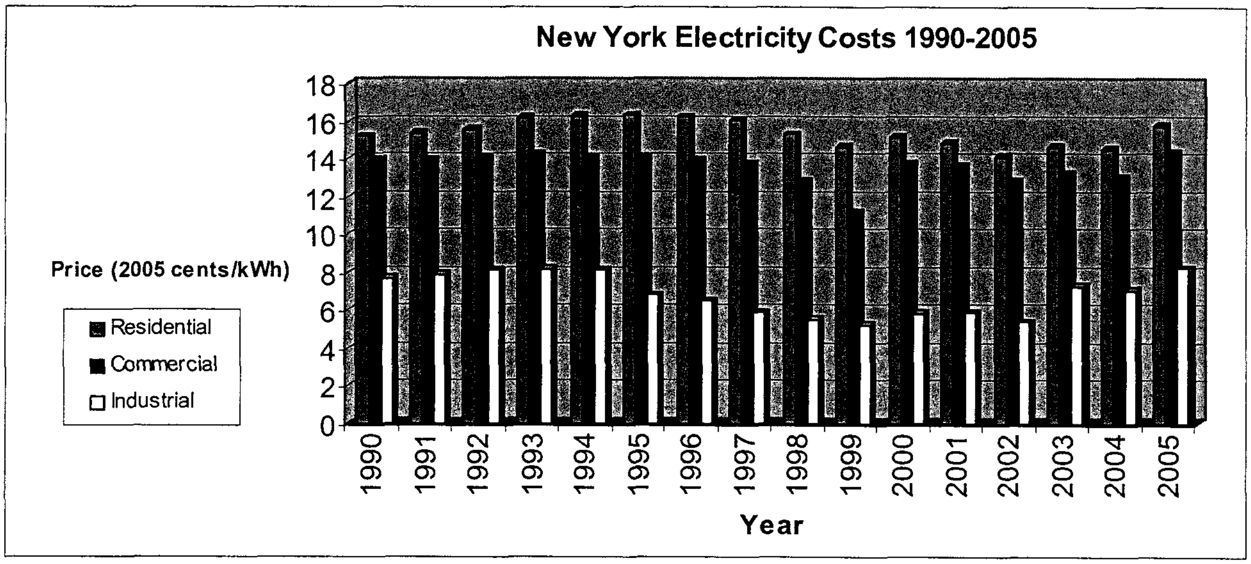
- Lower Real Prices: are prices lower than they were under the pre-1996, regulated regime?
- Smaller Comparative Price Increases: have prices in areas that have implemented competitive markets risen less than in areas that have maintained regulated monopolies?
- Lower Relative Prices: are prices lower now in deregulated areas than they would have been had deregulation not taken place?

In each instance, there is significant evidence to show that competitive markets have performed better than regulated monopoly structures.

Lower Real Prices

Contrary to the misperception that prices have increased since restructuring was undertaken in New York, an examination of EIA data demonstrates that competitive markets have held real prices down in all categories (Chart 4).

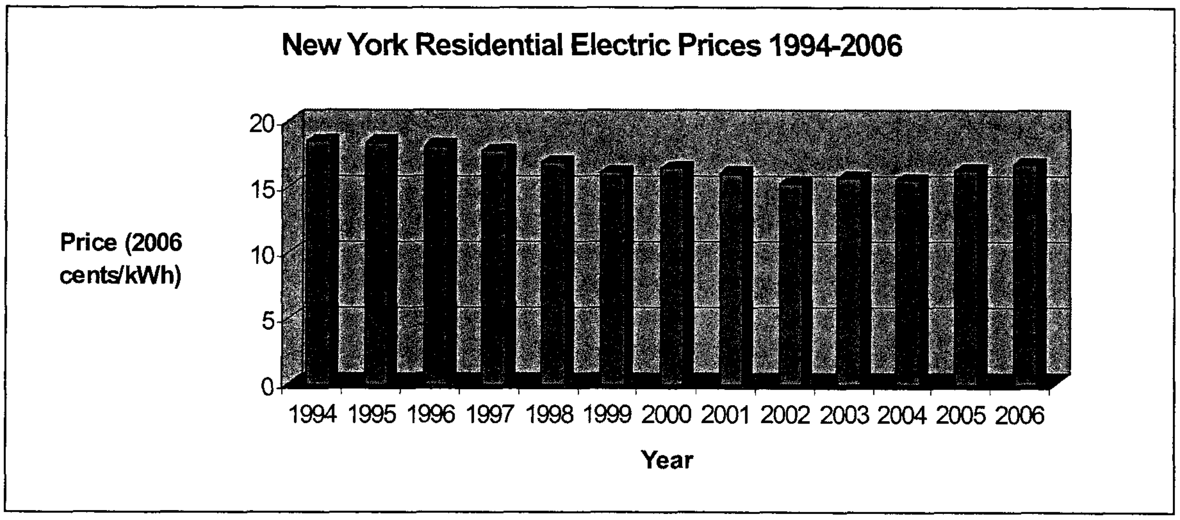
Chart 4



Source: EIA; http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept08ny.xls

The decline in real prices is particularly significant for residential customers from a high of 18.44 cents/kWh in 1994, on the eve of New York's deregulation endeavor, to 16.69 cents/kWh in 2006 (constant 2006 dollars) (Chart 5). Even with the recent rise in prices over the past two years, real residential electric prices in New York are considerably lower than they were prior to when restructuring commenced.

Chart 5



Source: Energy Information Administration

These sector-wide savings are tangibly demonstrated by the savings reported from the following customers:

- In 1997, the North Syracuse School District contracted with an ESCO (Noresco) to convert the Cicero-North Syracuse High School from electric to gas heat with a type of air conditioner known as a gas chiller. Software was also installed to regulate temperatures at different times during the day. In 2000, the District entered a similar contract with the company when it installed new lighting, energy efficient motors, gas kitchen appliances, new gas boilers, and new windows and doors in many of its buildings. Again, Noresco guaranteed a savings of $182,810 per year, with the District taking any savings beyond that. At the end of 2005, the District reported a total savings of $630,000 beyond its obligations to Noresco for the fiscal year April 1994 to March 1995.[42]

- In 2006, Westchester Presbyterian Hospital in White Plains worked with ConEdison Solutions and the New York State Energy Research and Development Authority to put a conservation program in place with the expectation of saving more than $200,000 a year.[43]

- The Rome Chamber of Commerce reports that its members saved $180,815 on energy costs in 2004 from their participation in the Integrys electricity savings program. Chamber members see an estimated annual savings of 5-20% on their utility rates.[44]

- In 2006, the Batavia City Council entered into an energy performance contract with Johnson Controls, Inc. which involved investment in conservation-oriented

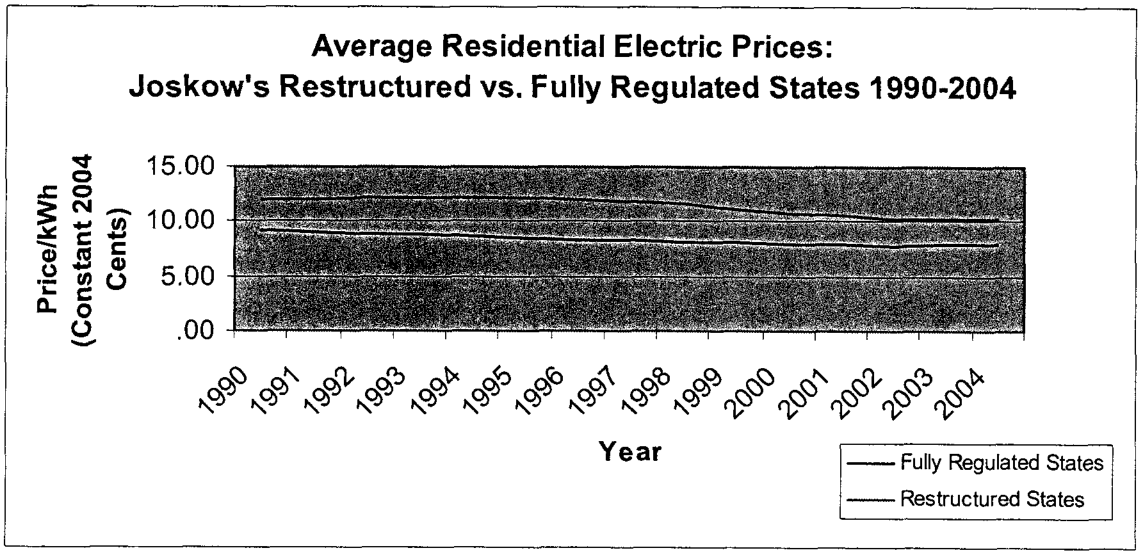
[42] Reaves, M. (2005). "Energy service company brings big savings to district; costs have been reduced $600,000 through earlier efforts," *The Post-Standard (Syracuse, NY)*, 12/29/05: p14.
[43] Drury, A. (2006). "Con Edison unit names new leader," *The Journal News (Westchester County)*. 6/22/06.
[44] Rome, New York Chamber of Commerce at http://www.romechamber.com

equipment. The contract projected annual energy and operational savings of $68,000 per year.[45]

Smaller Comparative Price Increases

One of the most comprehensive studies to date regarding comparative electricity prices in constant dollars found that, with the exception of Texas, the states that have embarked on electric restructuring experienced larger decreases than states that have remained under a regulated monopoly structure.[46] Using that study's categorization scheme of deregulated states, a further examination of EIA data confirms those findings. Taking the average real price trends from 1990 to 2004 in the study's cited restructured states and comparing them to the average real price trends in "fully regulated" states for the same period, restructured states saw real price reductions for the period of 14.1%, compared with real price reductions of 13.2% for states that still have regulated monopoly structures (Chart 6).[47]

Chart 6



Source: EIA Data

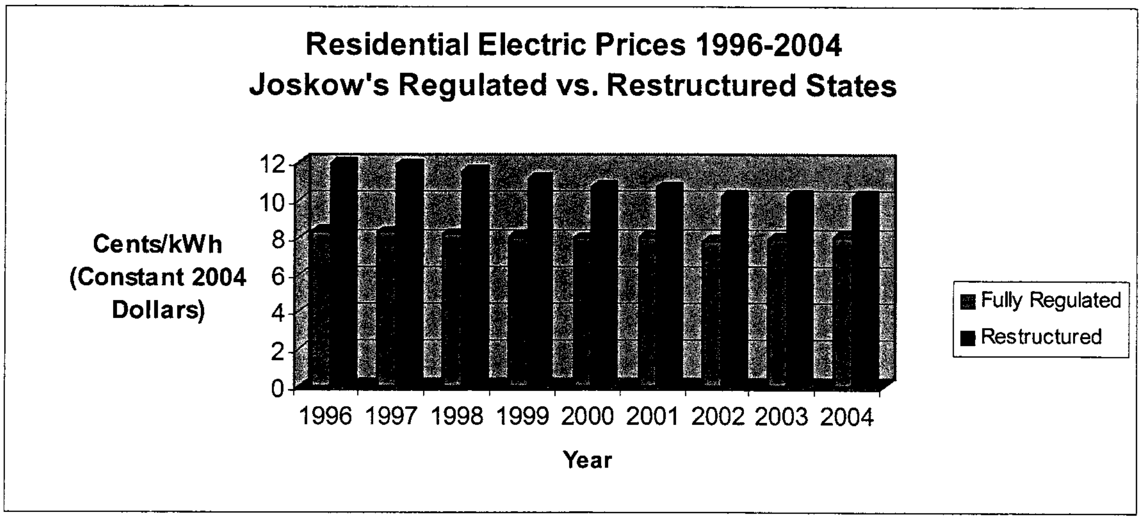
Indeed, from the mid-1990s, when the Commission undertook deregulation in New York, to 2004, restructured states have seen an average 15% decrease in residential electric prices, while fully regulated states have seen an average decrease of only 4.1% (Chart 7).

[45] Beck, J. (2006). "City aims to cut energy costs: Inks agreement to invest in more conservation-oriented equipment," *Daily News, The (Batavia, NY)*. 3/8/06.

[46] Joskow, P.L. (2005). *Markets for Power: An Interim Assessment.* Center for Energy and Environmental Policy Research. August, 2005. p.36.

[47] Calculated from AEI data. Completely deregulated states are Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas and Virginia; regulated monopoly states are Alabama, Colorado, Florida, Georgia, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, North Carolina, Rhode Island, South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, Wisconsin and Wyoming. See Appendix C.

Chart 7



Source: EIA Data

Lower Relative Prices

A study of two of the two mid-Atlantic regional electric trading markets – the New York Independent System Operator (NYISO) and Pennsylvania-New Jersey-Maryland (PJM) Interconnection – found that, while prices in the NYISO and PJM area increased from 1998 to 2004, they did not increase as much as they would have had deregulation not taken place. Prices have risen in general since 1997 because the impact of rising fuel prices that cannot be avoided through changes in market structure. However, in comparing actual price increases with models that projected price behavior had deregulation not taken place, that aggregate savings in the NYISO and PJM regions was $1.3 billion per year for the time period.[48]

In viewing the nominal price increases over the past few years, consumers, the media and, consequently, some policy-makers have focused far too much on short-term trends. Just as investors should not focus on one day's change in the stock market, short-term price increases brought about by unprecedented increases in the price of fossil fuels do not negate the benefits of the competitive market. Fuel prices have recently pushed up rates everywhere, whether in states still under the traditional regulated monopoly regime or in restructured states. In 2005, oil prices increased by 135% and natural gas prices increased by 210%. If restructured states had used the fuel-cost adjustment pass-throughs common in states with traditional regulated monopoly rate regulation, as downstate utilities commonly did, rates would have been 15% higher than the rates produced under restructuring.[49]

Just as investors should not focus on one day's change in the stock market, short-term price increases brought about by unprecedented increases in the price of fossil fuels do not negate the benefits of the competitive market.

[48] Harvey, S.M., McConihe, B.M. and Pope, S.L. (2006). *Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges*. LEGC, LLC. November, 2006.
[49] Alexrod, H.J., DeRamus, D.W. and Cain, C. (2006). "The Fallacy of High Prices," in *Public Utilities Fortnightly*. November, 2006.

Continued Environmental Protection

One of the most important successes of electric industry restructuring is the creation of a market for renewable energy generation, or "green power," which satisfies both the environmental yearnings of its purchasers and the need of its sellers to differentiate their product offerings.[50] ESCOs are uniquely positioned to offer consumers the opportunity to play a personal role in protecting the environment. ESCOs can provide service packages that typically include financing, installation, and maintenance of energy-saving capital improvements. Services are provided through performance contracts, which guarantee that payments will not exceed energy savings.[51]

As consumers become more sophisticated in evaluating purchasing choices in an expanding competitive electric market, the ability to choose energy produced from renewable energy sources has become increasingly important. Just as conservation-conscious consumers are weighing factors other than price when they purchase hybrid vehicles, so to, where the market structure allows for competition, options in the energy marketplace offer consumers opportunities to purchase environment friendly energy.

ESCOs are uniquely positioned to offer consumers the opportunity to play a personal role in protecting the environment.

A great deal of toxic air pollution can be avoided by shifting some of our electricity needs to renewable power sources such as wind, geothermal, solar and biomass. Several ESCOs offer the choice of green energy options for customers that want the opportunity to select from renewable energy resources that protect the environment and expand energy options. As more ESCOs enter the market and competitive markets continue to expand, the trend for specialized products will continue to grow. The benefits of this choice are potentially enormous:

- For each kilowatt-hour of electricity produced from renewable electricity sources, businesses can prevent approximately one pound of CO2 from going into the environment.
- A large grocery store could avoid putting over one million pounds of CO2 into the atmosphere each year by purchasing one third of its electricity requirements from wind, solar or other renewable power sources.
- If just 10 percent of New York's households purchased Green Power in conjunction with their electricity supply, it would prevent nearly three billion pounds of carbon dioxide, 13 million pounds of sulfur dioxide, and nearly four million pounds of nitrogen oxides from getting into our air each year.[52]

Perhaps no better example of the combination of savings and environmental responsibility exists than with Plainville Turkey Farms, Inc., in Plainville, New York. In 2003, Plainville Farms, producers of all-natural turkey products, signed with Community Energy to purchase wind-generated energy for its operations. The farm buys 708,000 kWhs of wind energy, accounting for 100% of the electricity required to grow its turkeys.

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[50] Reed, G. and Houston, A.H. *Status of US Market for Green Power*
[51] http://www.greenbiz.com/toolbox/essentials_third.cfm?LinkAdvID=8556
[52] Con Edison, available at http://www.poweryourway.com/pages/greenpower.pdf

The associated environmental benefits are equal to not releasing 708,000 pounds of carbon dioxide, 5,430 pounds of sulfur dioxide, and 2,138 pounds of nitrous oxides into the atmosphere, which can be equated to planting over 74,000 trees or taking 98 cars off the road each year.[53]

To help all consumers identify green energy suppliers, the PSC has an Environmental Disclosure Label Program, which publishes the fuel source and air emission for each ESCO serving New York customers. Environmental Disclosure Labels allow consumers to compare and make choices based on the nature of power generation.[54]

CONCLUSION

In its opening paragraph, this White Paper outlined criteria by which the success of restructuring the energy industry in New York should be judged. Those criteria included increased supply choices through value-added products and services; downward pressure on prices; enhanced price transparency for all consumers; technological innovation and new products and services; and environmental improvements through conservation and demand response. Through qualitative and quantitative measurements, using academic and trade journals, government agency resources, independently constructed industry analyses and EIA data, each of the criteria was examined. Though the restructuring effort is not yet complete, both the quantitative and qualitative data firmly indicate that the criteria have so far been successfully met.

By all measurements, where the PSC has implemented a retail market structure that enables customers to know their true costs of consumption through market-reflective price signals and enables ESCOs to use this information to develop a variety of product offerings tailored specifically to the customer's needs, the benefits of retail competition have been realized. That is, downward pressure has been applied to energy prices, customer choice has increased, and environmental, reliability, and consumer protection benefits have continued, all while creating economic development across the state.

However, for those consumer sectors where this retail market structure has not been implemented, these benefits have been slower in coming, leaving retail competition open to criticism particularly from those sectors who have sought to erect roadblocks to restructuring every step of the way over the past decade. Nevertheless, this analysis has demonstrated that New York is on the verge of a new era of vibrant competition for residential and smaller commercial customers if the present retail market structure is allowed to continue and to expand.

Lower energy prices brought about by the continued downward pressure that robust and sustainable retail competition structures can provide will attract new business to New York while at the same time retain businesses already in New York, and help them expand their operations and create jobs. Emerging new technologies will allow ESCOs to offer commercial and residential consumers rational choices that were unimaginable just a few years ago – choices that will result in cleaner air, lowered dependence on imported energy and a more competitive economy on the global stage.

[53] More information available at http://www.plainvillefarms.com.
[54] Available at http://www3.dps.state.ny.us/e/energylabel.nsf/.

These results should serve as a thoughtful and positive development to policy-makers in both the Executive Branch and the State Legislature who may view nominal prices as an indication that retail competition has not produced benefits for New York's consumers. On the contrary, New York has seen declining real energy prices and an increasingly vibrant, stable competitive retail market. It is doing better than most other states that have undertaken restructuring, and outperformed those states that have yet to embark on restructuring.

It is therefore imperative for the Spitzer Administration to continue to implement policies that will improve the existing retail market structure for residential and small commercial customers that will enable these customers to further enjoy the benefits of retail competition envisioned by the PSC. The Administration is undertaking to bring the benefits of competition in other vital public policy areas such as education; it should similarly work toward unlocking the undisputed benefits of retail electricity competition for New York's residents and small businesses.

Simultaneously, the Administration should be reluctant to even entertain policies – such as a default service based on long-term multi-year generation procurement contracts -- that will move customers away from their ability to receive market-reflective price signals that will unlock for them the benefits of retail competition. As discussed in great detail in the Federal Competition Report, the ability of retail competition to remain robust and sustainable and fulfill all of the goals of deregulation is directly dependent upon the retail market structure that is permitted to operate.

A grave concern arises when utilities provide a long-term fixed-price. Not only would such an approach harm the successful retail market structures already in place in the larger customer sectors and fatally arrest the market's continued development in the smaller customer sectors, but it would shift significant risks back to captive ratepayers and expose them to future sources of stranded costs. Specifically, this structure enables utilities to draw upon their regulated transmission and distribution (T&D) customer rate base to shield customers from the market-reflective price signals that serve as the building blocks of the competitive (i.e., non-T&D) retail market.

In addition, while such policies have been proposed as a mechanism to attract investment in new generation, they can also weaken a utility's balance sheet and, by tying up capital and credit lines, either impede or make it more expensive for a utility to invest in its transmission and distribution system.[55] Ultimately, efforts to re-institute cost of service regulation will fail to benefit New York's consumers and make New York's economy less competitive for the ESCO industry and the over 1.3 million customers – ranging from residential consumers to Fortune 100 companies – served by the competitive retail electric industry. In implementing a forward-looking energy policy, New York should seek ways to address existing problems that incorporates retail competition and the many irrefutable benefits it provides.

[55] See April 3, 2007publication by Standard & Poor's "Re-Regulation of U.S. Electric Utilities: The Toothpaste Challenge"

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STATE COMPETITIVE PROCUREMENT: A PARTIAL SURVEY OF BEST PRACTICES

> It is a near truism among economists and policymakers that competition in virtually every sector of the U.S. economy provides consumers with significant benefits. Market economies give producers the incentives to invest and innovate, while competition among producers disciplines prices. Consumers benefit from the resulting increased efficiency, increased output, and ultimately lower prices.[1]

I. Scope

A joint task force convened by the National Association of Regulatory Commissioners (NARUC) and the Federal Energy Regulatory Commission (FERC) is examining the subject of competitive procurement for electric power resources in the states and at the federal level. The Dickstein Shapiro firm, at the request of the Electric Power Supply Association (EPSA), has prepared this document to assist the task force's deliberations on this important topic. In particular, EPSA has asked us to prepare a preliminary survey – for those states that have not traditionally used a competitive method to meet customers' supply needs – of "best practices" for competitive procurement in the states. In addition, we have attached as an appendix to this document a model rule for state competitive procurement practices, based upon the results of our survey.

Competitive bidding for infrastructure improvements has been a feature of many state procurement regimes for only the past twenty years, i.e. since the early years of the competitive power sector after enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA). In the late 1980s and early 1990s, several utilities, most notably Virginia Electric and Power Company, ceased building their own generation and elected to fill their capacity needs through long-term competitive bidding solicitations. Since that time, many states have developed competitive bidding regimes, under auspices of either statutory authority, regulatory rulemaking, or administrative adjudication.

New power generation resources, and in some cases other infrastructure needs, are now developed under a variety of mechanisms.

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[1] An Empirical Assessment of the Benefits of Competition in Wholesale and Retail Markets Electric Markets, prepared for Constellation Energy Group by Bates White, LLC (May 2006) at. p.1.

Our survey has focused on five elements that characterize competitive bidding regimes:

(A) Integrated Resource Planning / Least Cost Planning: a comprehensive, coordinated planning process, typically run under the auspices of a state regulatory body that identifies the medium- and long-term resource needs of load serving entities, and determines the optimal way to meet those needs.

(B) Requests For Proposal: in competitive markets, the process by which the Load Serving Entities' (LSE) needs, as identified in the planning process, are met.

(C) Independent Oversight: in service territories or jurisdictions where the LSE remains in the generation business, either as a utility operation or through a competitive power affiliate, independent oversight ensures that the LSE does not favor affiliated generation options over competitively superior alternatives. In some jurisdictions, this function is filled by, or in conjunction with, public service commission (PSC) staff.

(D) The Role of the Utility: the rules that govern: (1) the relationships and permissible interactions between the LSE and its affiliates who compete to serve load, and (2) the circumstances under which utility rate basing of new resources is favored or allowed.

(E) Procuring Specialized Products Such as Renewables: While most RFPs are for commodities without a stated preference for fuel source, the growing focus on renewable power resources has spawned numerous solicitations for resources with particular environmental capabilities.

II. Elements of a Model Competitive Procurement.

A. The Integrated Resource Plan.

Example A1: Colorado Department of Regulatory Agencies -- Part 3 – Rules Regulating Electric Utilities 3604. Contents of the Least – Cost Resource Plan

The utility shall file a plan with the Commission that contains the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following:

a. A statement of the utility-specified resource acquisition period, and planning period. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire least-cost plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period lengths were chosen in light of the assessment of base-load, intermediate and peaking needs of the utility system.

b. An annual electric demand and energy forecast developed pursuant to rule 3606.

c. An evaluation of existing resources developed pursuant to rule 3607.

d. An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3608.

e. An assessment of need for additional resources developed pursuant to rule 3609.

f. A description of the utility's plan for acquiring these resources pursuant to rule 3610.

g. The proposed RFP(s) the utility intends to use to solicit bids for the resources to be acquired through a competitive acquisition process, pursuant to rule 3612.

h. An explanation stating whether current rate designs for each major customer class are consistent with the contents of its plan. The utility shall also explain whether possible future changes in rate design will facilitate its proposed resource planning and resource acquisition goals.

Example A2 Oklahoma Corporation Commission

SUBCHAPTER 37. INTEGRATED RESOURCE PLANNING

a. The purpose of this Subchapter is to establish fair, just and reasonable rules and procedures for Commission review of the resource plans of utilities. The utility resource plans establish additional bases for substantial investment and expenses incurred by utilities to provide electric supply to retail consumers. The practices and policies embodied in a utility's resource plan have direct, substantial effects on the costs and reliability of the electric supply to be provided to retail consumers in Oklahoma. Resource planning is a complex process affecting decisions that account for a substantial portion of the total cost of electricity over the long term, including investments in generation and transmission facilities, purchases of power and fuel supply, and investments in energy efficiency. Recognizing the significance of the costs incurred based on resource plans, the Commission believes it is in the best interest of retail ratepayers and the utilities providing regulated retail electric supply to establish regular review of the utilities resource plans to ensure that the utilities' resource overall cost of power supply to retail ratepayers is fair, just, and reasonable.

b. This Subchapter establishes fair, just and reasonable procedures for:

(1) Setting standards for prudent resource planning;

(2) Conducting periodic review of utility resource plans;

(3) Participation of stakeholders, particularly those representing ratepayer interests, to review and have input into the utility's resource plans and the Commission's resource planning policies;

(4) Establishing the need for additional resources serving as the basis for long-term competitive procurement of resources, including, but not limited to, utility construction of new electric generation facilities, the utility purchase of existing electric generation facilities; and the purchase of long-term power supplies;

(5) Establishing objectives and action plans consistent with Commission resource planning policies;

(6) Establishing appropriate plans for capital expenditures for equipment or facilities at utility generation facilities necessary to comply with the Federal Clean Air Act, as amended, and other federal, state, local, or tribal environmental requirements;

(7) Establishing a clear, before-the-fact foundation for the recovery of prudently incurred investment and expenses in subsequent rate and fuel and purchased-power cost recovery proceedings; and

(8) Establishing the appropriate portfolio of products to be obtained through competitive procurement.

Example A3 – Georgia Code § 46-3A-1

As used in this chapter:

'Plan' means an integrated resource plan which contains the utility's electric demand and energy forecast for at least a 20 year period, contains the utility's program for meeting the requirements shown in its forecast in an economical and reliable manner, contains the utility's analysis of all capacity resource options, including both demand-side and supply-side options, and sets forth the utility's assumptions and conclusions with respect to the effect of each capacity resource option on the future cost and reliability of electric service. The plan shall also:

(A) Contain the size and type of facilities which are expected to be owned or operated in whole or in part by such utility and the construction of which is expected to commence during the ensuing ten years or such longer period as the commission deems necessary and shall identify all existing facilities intended to be removed from service during such period or upon completion of such construction;

(B) Contain practical alternative to the fuel type and method of generation of the proposed electric generating facilities and set forth in detail the reasons for selecting the fuel type and method of generation;

(C) Contain a statement of the estimated impact of proposed and alternative generating plants on the environment and the means by which potential adverse impact will be avoided or minimized;

(D) Indicate in detail the projected demand for electric energy for a 20 year period and the basis for determining the projected demand;

(E) Describe the utility's relationship to other utilities in regional associations, power pools, and networks;

(F) Identify and describe all major research projects and programs which will continue or commence in the succeeding three years and set forth the reasons for selecting specific areas of research;

(G) Identify and describe existing and planned programs and policies to discourage inefficient and excessive power use; and

(H) Provide any other information as may be required by the commission.

Comments

Integrated resource planning (IRP), also known as least-cost planning, is the time-honored method whereby utilities forecast their needs over a defined time horizon and develop the optimal means to meet those needs. Traditionally, IRP processes have been conducted at the state level, under the auspices of a state regulatory authority, and address all aspects of the utility's medium and long-term needs: generation, transmission, distribution, conservation and demand-side programs, renewable power, etc.). A completed IRP process is usually the precursor or predicate for approval by the regulatory authority of the utility's proposed means for meeting its identified needs. The utility, through the IRP process, is tasked with demonstrating that its proposal is the optimal (which is usually, but not always, the least cost) means for meeting those needs.

As the above examples demonstrate, the traditional IRP process has been reexamined in recent years, for a variety of reasons. First, passage of the three major energy acts of the past few decades (PURPA, the Energy Policy Act of 1992, and the Energy Policy Act of 2005) has established definitively that electric power generation is a competitive industry, not a "natural" monopoly. The result is that many IRP processes, such as the ones cited above, have explicitly directed load serving entities (LSEs) to consider non-utility generation in their generation planning processes. The objective is not necessarily to displace the utility-build option, but rather to render it one option among many, with the LSE proceeding down that path only upon a demonstration that there are no superior options in the wholesale competitive market.

Second, the FERC has in recent years put strong emphasis on the necessity for a planning process at the federal level. In particular, regional planning is a centerpiece of the FERC's recently concluded Order No. 890, and is an important part of the development of ISOs and RTOs in the organized markets. While the FERC's focus with regard to planning has been more on transmission planning than on generation development, both the states and the FERC appear to realize that there is no neat dividing line between the two planning regimes; an optimal planning process should in fact treat generation, transmission and other options (such as demand side planning) as a menu of resources available to meet the LSE's long-term needs, not as freestanding topics to be addressed separately and independently of one another.

Finally, the FERC and state regulatory authorities have indirectly cooperated in IRP processes where LSEs have proposed meeting their generation needs through power purchase agreements with their non-utility affiliates. In those instances, the state regulator essentially has authority over the prudence of purchase by its jurisdictional LSE, and the FERC has authority over the wholesale sale by the non-utility affiliate. In the so-called *Edgar*[2] line of cases, the FERC, focusing on the potential for affiliate abuse, has laid out a test whereby the seller must demonstrate the absence of such abuse in the contract award. The centerpiece of that burden of proof is demonstrating some form of competitive solicitation (or a strong proxy for it) that shows that the affiliate deal was reasonable, based on a combination of price and non-price factors, and that the process for deciding to contract with the affiliate was fair.

B. The RFP

Example B1 - Utah § 54-17-201

Solicitation process required – Exception.

(1) (a) An affected electrical utility shall comply with this chapter to acquire or construct a significant energy resource after February 25, 2005.

(b) Notwithstanding Subsection (1)(a), this chapter does not apply to a significant energy resource for which the affected electrical utility has issued a solicitation before February 25, 2005.

(2)(a) Except as provided in Subsection (3), to acquire or construct a significant energy resource, an affected electrical utility shall conduct a solicitation process that is approved by the commission.

(b) To obtain the approval of the commission of a solicitation process, the affected electrical utility shall file with the commission a request for approval that includes:

(i) a description of the solicitation process the affected electrical utility will use;

(ii) a complete proposed solicitation; and

(iii) any other information the commission requires by rule made in accordance with Title 63, Chapter 46a, Utah Administrative Rulemaking Act.

(c) In ruling on the request for approval of a solicitation process, the commission shall determine whether the solicitation process:

[2] Boston Edison Company Re: Edgar Electric Company, 55 FERC P 61,382 (1991)

(i) complies with this chapter and rules made in accordance with Title 63, Chapter 46a, Utah Administrative Rulemaking Act; and

(ii) is in the public interest taking into consideration:

(A) whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in the state;

(B) long-term and short-term impacts;

(C) risk;

(D) reliability;

(E) financial impacts on the affected electrical utility; and

(F) other factors determined by the commission to be relevant.

(d) Before approving a solicitation process under this section the commission:

(i) may hold a public hearing; and

(ii) shall provide an opportunity for public comment.

(e) As part of its review of a solicitation process, the commission may provide the affected electrical utility guidance on any additions or changes to its proposed solicitation process.

(f) Unless the commission determines that additional time to analyze a solicitation process is warranted and is in the public interest, within 90 days of the day on which the affected electrical utility files a request for approval of the solicitation process, the commission shall:

(i) approve a proposed solicitation process;

(ii) suggest modifications to a proposed solicitation process; or

(iii) reject a proposed solicitation process.

(3) Notwithstanding Subsection (2), an affected electrical utility may require or construct a significant energy resource without conducting a solicitation process if it obtains a waiver of the solicitation requirement in accordance with Section 54-17-501.

(4) In accordance with the commission's authority under Subsection 54-12-2(2), the commission shall determine:

(a) whether this chapter or another competitive bidding procedure shall apply to a purchase of a significant energy resource by an affected electrical utility from a small power producer or cogenerator; and

(b) if this chapter applies as provided in Subsection (4)(a), the manner in which this chapter applies to a purchase of a significant energy resource by an affected electrical utility from a small producer or cogenerator.

Comments

The centerpiece of the competitive procurement process is the request for proposals (RFP), which defines the product the LSE is seeking and offers the opportunity to qualified competitors. Conceptually, RFPs in the electric power sector are no different from competitive solicitations in other sectors; the overlay of the regulatory structure, however, renders RFPs in the U.S. power sector materially different. For example, the LSE buyer in many U.S. markets is a regulated monopsonist, and its procurement decisions are thus regulated by its state PSC. In addition, the LSE buyer may itself be a competitor in the RFP, leading to the necessity for independent oversight of the procurement. (<u>See</u> Section C, below.) The Utah statutory provision cited above addresses many of these special issues and concerns surrounding the competitive procurement of electric generation resources, and in addition provides an opportunity for the LSE to seek waiver of these requirements for good cause shown.

Finally, it is essential that the RFP "rules of the road" be developed through a comprehensive stakeholder process that permits the involvement of the LSE, potential competitors who might serve the load, the independent monitor who will oversee the RFP process, consumer groups and regulatory authorities. Much as is the case with regard to the transmission planning process that the FERC addressed in detail in Order No. 890, a stakeholder process to structure RFP protocols ensures the optimal, cost-effective development of these large infrastructure projects, and can also inoculate the RFP process against charges of manipulation, exclusion or incompleteness.

C. The Independent Monitor

Example C1 – Arizona Docket No. E-00000A-02-0051 et al. (2002)

To assist the Staff and to assure all parties to the solicitation for power supplies that the process employed is conducted in a transparent, effective, efficient and equitable manner, an Independent monitor will be appointed by the Staff to the Commission to oversee the conduct of the Solicitation. The Independent Monitor will be selected by the Staff and will work at the Staff's direction. Any person expecting to participate in the solicitation process may suggest to the Staff any individual to serve as the Independent monitor. The utility will retain the Independent Monitor selected by the Staff and will be responsible for all related costs. The independent Monitor shall submit all invoices to the Staff for review. The Staff shall forward the invoices to the utility with a recommendation as to payment.

The Independent Monitor will be responsible for:

- monitoring all communications regarding the solicitation by and among the utility and any bidders or potential bidders;
- evaluating the adequacy, accuracy and completeness of all solicitation materials, and the quality of the evaluations conducted;
- monitoring any negotiations conducted by the utility and any bidder;
- assisting the Staff in developing the "prices to beat" and such other tasks as required;
- advising the Staff and the utility of any issue affecting the integrity of the solicitation process and providing the utility an opportunity to remedy the defect identified;
- periodically submitting status reports to the Commission and the Staff on the solicitation being

conducted, noting any deficiencies identified in the preparation of solicitation materials, maintenance of records, communications with bidders, or in evaluating or selecting bids;

- advising the Commission and the Staff of significant unresolved issues as they arise;
- after bids have been selected, preparing and submitting a report to the Commission detailing the Independent Monitor's observations and findings relating to the conduct of the solicitation and any recommendations for improvements of the solicitation process employed in the initial solicitation; and
- making all written status reports and the final reports to the Commission available to any person having an interest in the solicitation.

The Independent Monitor shall have full access to all materials used in or relating to the Solicitation. The utility shall make its personnel available for consultation with the Independent Monitor as requested. The Independent Monitor shall attend, in person or telephonically, any negotiations conducted with bidders.

Following the bidders conferences and before the distribution of solicitation materials, the Independent Monitor shall submit a status report to the Commission and the Staff noting any unresolved issues that could impair the equity or appropriateness of the solicitation process.

Example C2 – Oklahoma Regulations Subchapter 34,

165:35-34-3 RFP Competitive Bidding Procurement Process

(a) Independent Evaluator

The Commission may, at its discretion, retain and compensate an Independent Evaluator to monitor the RFP and competitive bidding process. Notwithstanding the foregoing, the Commission shall retain an Independent Evaluator to monitor the RFP and competitive bidding process in the following instances: (i) when an affiliate of the utility is anticipated to participate in the competitive bidding process; (ii) when the RFP and bid resulting there from is expected to have a material impact on the utilities' cost of providing electricity to its customers, or (iii) when it is anticipated that the utility may participate as a bidder in the competitive bidding process. The Commission shall establish the minimum qualifications and requirements for an Independent Evaluator and ensure the Independent Evaluator is financially and substantively independent from any soliciting electric utility or affiliate thereof, complaining entity, and any potential bidder.

The Independent Evaluator will report to the Commission and the Attorney General.

If the Independent Evaluator's conclusion is different from the conclusion of the soliciting utility about the winning bidder(s), the Independent Evaluator and utility may attempt to resolve such differences. In the event the Independent Evaluator and utility cannot resolve their differences, the soliciting utility will determine which bid(s) is successful. The Independent Evaluator shall submit its independent evaluation to the Commission.

As part of its contract with the Independent Evaluator, the Commission shall require the Independent Evaluator, to enter into an agreement to keep all information confidential that pertains to the disclosure and use of any models analytical tools, data, or other materials of a confidential or proprietary nature provided or made available by the soliciting utility in conjunction with the competitive bidding process.

Example C3 – Arizona Docket No. E-00000A-02-0051 et al. (2002)

III. Independent Oversight

We agree with Staff and AUIA, and will again clarify that the utilities have the right to reject all bids if the bids do not reasonably meet the needs of the utility and its customers. We do expect the utilities to give serious consideration to all bids received, including long- and short-term bids, which consideration should include sound economic and deliverability analysis of the bids. The utilities' goal should be to obtain for their customers the least-cost mix of reliable power over the long term, while being mindful of the air quality and water issues effects of their procurement decisions, as well as whether their procurement decisions will further this Commission's goal of encouraging the development of a competitive wholesale generation market in Arizona. While we are not requiring APS and TEP to accept bids in the solicitation process that are unreasonable, uneconomical, or unreliable, APS and TEP should be on notice that the Commission will closely scrutinize the offered bids and the utilities' procurement decisions based on those bids for conformity with those goals. If the utility accepts no bids, the utility shall notify the Commission by filing a detailed written explanation within 72 hours after its decision. The Commission may take whatever action it deems appropriate at that time.

Comments

Perhaps the most important facet of a well-designed competitive procurement process is a defined and adequately empowered independent monitor. The core reason for an independent monitor is that competitors will not participate in procurement regimes that are or are perceived to be "rigged" or slanted in the direction of the LSE or its affiliates. The importance of the independent monitor is well stated in the following quote from the Arizona Independent Monitor after that state's load was opened up to all-source competitive bidding several years ago:

> [I]n order for the Solicitation to attract wide participation, the process had to be accepted by participants as fair, open, and transparent. To achieve this, prospective bidders and interested persons who agreed to keep certain information confidential had the opportunity to review supporting data and draft documents in advance of the RFP... Many bidders and other interested persons provided comments to the utilities, the Independent Monitor, or the Staff regarding the completeness or quality of the information provided... Bidders' conferences were held so that all interested parties had the opportunity to ask questions directly of the utilities as well as to identify deficiencies in the Solicitation documents or supporting data.[3]

EPSA's recent white paper on well-designed competitive solicitations states the reasons for an independent monitor as follows:

> The decision on whether to use an independent monitor is driven primarily by three factors: (1) the desire to assist state regulatory commission staff with logistical and technical assistance; (2) whether a utility affiliate or the utility's self-build option participates in the solicitation; and (3) an assessment of the need to enhance confidence among stakeholders that the solicitation is credible.

[3] Independent Monitor's Final Report on Track B Solicitation to the Arizona Corporation

D. The Role of the Utilities

Example D1 – Oklahoma Corporation Commission

IV. Standards of Conduct / Codes of Conduct

(a) Affiliate Bidders' Requirements

Each soliciting utility affiliate that intends to bid shall disclose publicly, in writing, the names and titles of the members of the affiliate's "Bid Team." Each soliciting utility shall disclose publicly, in writing, the names and titles of the members of its "Evaluation Team." A Bid Team develops the affiliate's bid and, to assure fairness, is not involved, directly or indirectly, in the evaluation or selection of bids. An Evaluation Team evaluates bids, selects the successful bidder and, to assure fairness, is not involved, directly or indirectly, in the development of the affiliate's bid.

Each soliciting utility and bidding affiliate shall assure that the Bid Team and the Evaluation Team and any member of either do not engage in any communications, either directly or indirectly, regarding the RFP or the competitive bidding process. For bidder and Commission assurance, the soliciting utility and bidding affiliate shall execute an acknowledgement that the utility and affiliate have not and will not in the future so communicate, other than to submit and receive the bid at the appropriate time. The Bid Team and Evaluation Team may communicate as part of a bidding technical conference of which potential bidders or all actual bidders, if bids have already been submitted, are given adequate notice and opportunity to attend.

The Evaluation Team shall report to the Independent Evaluator, any contact or communications by any bidder, including the Bid Team, and advise the bidder any future contact must be directed to the Independent Evaluator. Bidders and the Evaluation Team may communicate as part of a bidding technical conference of which potential bidders or all actual bidders, if bids have already been submitted, are given adequate notice and opportunity to attend.

In addition, the record in this proceeding supports a requirement that APS' parent and affiliates, including but not limited to M&T, PWEC and Pinnacle West, who may be involved in the preparation of a bid in the solicitation process shall not have contact with employees that will conduct the solicitation. We do not wish to harm APS customers by depriving APS of access to needed expertise provided by Pinnacle West "shared services," such as consulting legal counsel or in-house environmental experts, the examples provided by APS in its Reply Brief. However, we see no reason to allow APS' parent and affiliates, including but not limited to M&T, PWEC and Pinnacle West, access to such expertise if such access could provide even an appearance of impropriety in the solicitation process. We will therefore require that for the purposes of the solicitation and procurement, APS shall prohibit personnel who provide advice to APS in the solicitation process from communicating with personnel working for APS' parent or affiliate who may be involved in the preparation of a bid in the solicitation process, concerning any business matter related to APS' parent and affiliates pertaining to the Track B solicitation. Notwithstanding any other provision of this Opinion and Order to the contrary, nothing herein shall be construed as prohibiting APS, Pinnacle West, or PWEC officers and directors from providing corporate oversight, support and governance to their employees so long as such activities do not favor PWEC in Track B or provide PWEC with confidential bidding information during the Track B procurement that is not available to all other Track B bidders; nor prohibiting APS or Pinnacle West employees from communicating with PWEC employees about non-Track B matters. If APS affiliates, including but not limited to M&T, PWEC and Pinnacle West, require access to expertise that is dedicated to APS in the procurement process, they can obtain such expertise elsewhere, at their own expense.

Comments

As previously discussed, the advent of wholesale competition does not mean that LSEs or their affiliates are precluded from construction. Should an LSE or its affiliate choose to compete to serve load, however, a credible system must be in place to ensure that that option, if selected, is the best possible deal for consumers.

The issue of utility building arises in at least two contexts. In the first instance, the LSE or its affiliate seeks to compete for load. In this instance, the paramount concern is that the LSE be compelled to compete under the same rules, terms and conditions as other, non-affiliated competitors, including being held prospectively to the conditions under which the opportunity is awarded. This situation is best addressed by the terms of the bid design, in particular the design of the RFP so as to be neutral to the identity or affiliation of the bidders, and by the presence of the independent monitor to ensure that the bid protocols are followed.

The second instance arises where the LSE offers itself as the sole source to serve load, either as a utility-build / ratebased option or through a PPA with its affiliate, and asks the regulator to forego or waive the competitive procurement process so that it may do so. As suggested by the recent litigation on this topic in Georgia, the LSE should be tasked with a material burden of proof before a regulator should grant any request of this order.

E. Renewables and Other "Specialized" Products

Example E1 – Code of Colorado Regulations § 3651

(6) Renewables and Other Specialized Products

Overview and Purpose

The purpose of these rules it to establish a process to implement the renewable energy standard for qualifying retail utilities in Colorado, pursuant to the power to regulate public utilities delegated to the Commission by §24-4-101 C.R.S., *et seq.*, §40-2-108 C.R.S., §40-3-102 C.R.S., §40-3-103 C.R.S., §40-4-101 C.R.S., and §40-2-124 C.R.S.

Section 40-2-124 was enacted by the voters of the State of Colorado as 2004 Ballot Amendment 37 and was amended by the 2005 Colorado General Assembly by Senate Bill 05-143.

Energy is critically important to Colorado's welfare and development, and its use has a profound impact on the economy and environment. Growth of the state's population and economic base will continue to create a need for new energy resources, and Colorado's renewable energy resources are currently underutilized.

Therefore, in order to save consumers and businesses money, attract new businesses and jobs, promote development of rural economies, minimize water use for electricity generation, diversify Colorado's energy resources, reduce the impact of volatile fuel prices, and improve the natural environment of the state, it is in the best interests of the citizens of Colorado to develop and utilize renewable energy resources to the maximum practicable extent.

It is the policy of this State to encourage local ownership of renewable energy generation facilities to improve the financial stability of rural communities.

Comments

As previously noted, competitive procurement is thought of primarily as a competition among generators to serve load. Competitive procurement, however, may be thought of more broadly as a tool for meeting all the needs of the electric power sector, including reliability needs, solutions for transmission constraints, and demand-side resources. One area that has lent itself well to competitive solicitation is the growing area of renewable resources. Approximately half the states currently have renewable portfolio standards (RPS), provisions that require the LSE to have a specified percentage of load served by renewable power resources. "Renewables-specific" RFPs have proven to be an effective way of developing such resources in many states. The cited Colorado statutory provision is a good example of such a program.

APPENDIX

STATE COMPETITIVE PROCUREMENT PROCEDURES: MODEL RULES AND BEST PRACTICES

A. The Integrated Resource Plan.

Each load-serving entity ("LSE") shall file a plan with its state public service commission ("PSC") that contains the information specified below.

1. A statement of the LSE-specified resource acquisition period, and planning period. The LSE shall include a detailed explanation as to why the specific period lengths were chosen in light of the assessment of base-load, intermediate and peaking needs of the utility system.

2. An annual electric demand and energy forecast.

3. An evaluation of existing resources.

4. An assessment of planning reserve margins and contingency plans for the acquisition of additional resources.

5. An assessment of need for additional resources.

6. A description of the LSE's plan for acquiring these resources.

7. The proposed Request For Proposals ("RFP") the LSE intends to use to solicit bids for the resources to be acquired through a competitive acquisition process.

8. An explanation stating whether current rate designs for each major customer class are consistent with the contents of its plan. The LSE shall also explain whether possible future changes in rate design will facilitate its proposed resource planning and resource acquisition goals.

9. To the extent feasible, the PSC shall try to ensure that the Integrated Resource Plan (IRP) takes into consideration state and regional transmission plans and alternatives to generation options, coordinating generation and transmission planning on a regional basis to increase the efficiency of existing infrastructure and regional planning.

B. The Request for Proposals ("RFP")

(1) All acquisitions or construction of energy resources greater than __ MW shall be done pursuant to an RFP process that is approved by the PSC unless the LSE can establish by convincing evidence that such RFP process is not feasible or without purpose.

(2) The RFP shall be developed pursuant to a stakeholder process that includes, to the maximum extent feasible, participation by the LSE, potential wholesale competitors who might serve the load, the independent monitor who will oversee the RFP process, consumer groups and regulatory authorities.

(3) To obtain the approval of the PSC of a proposed RFP process, the LSE shall file with the PSC a request for approval that includes:

(a) a description of the solicitation process the affected LSE will use;

(b) a proposed draft RFP; and

(c) any other information the PSC requires by rule.

(4) In ruling on the request for approval of a RFP process, the PSC shall determine whether the solicitation process:

(a) complies with applicable law and

(b) is in the public interest taking into consideration:

(i) whether it will likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of the LSE;

(ii) long-term and short-term impacts;

(iii) risk;

(iv) reliability;

(v) financial impacts on the affected LSE; and

(vi) other factors determined by the PSC to be relevant.

(5) As part of its review of a solicitation process, the PSC may provide the affected LSE guidance on any additions or changes to its proposed RFP process. If the LSE or an affiliate of the LSE is permitted to participate in the RFP process, such entity shall (a) participate in that process under the same terms and conditions as any other competitor, with no opportunity to amend its bid or solicitation response that is different from the opportunity provided to all other competitors, and (b) be subject to the procedural protections set forth in Section D (The Role of the LSE).

(6) Unless the PSC determines that additional time to analyze a solicitation process is warranted and is in the public interest, within 90 days of the day on which the affected electrical utility files a request for approval of the solicitation process, the PSC shall:

(i) approve a proposed RFP process;

(ii) suggest modifications to the proposed RFP process; or

(iii) reject the proposed RFP process.

C. The Independent Monitor

(1) The PSC may, at its discretion, retain and compensate an Independent Monitor ("IM") to monitor the RFP and competitive bidding process. Notwithstanding the foregoing, the PSC shall retain an IM to monitor the RFP and competitive bidding process in the following instances: (i) when an affiliate of the LSE is anticipated to participate in the RFP; (ii) when the RFP and bid resulting therefrom is expected to have a material impact on the LSE's cost of providing electricity to its customers, or (iii) when it is anticipated that the LSE may participate as a bidder in the competitive bidding process. The PSC shall establish the minimum qualifications and requirements for an IM and ensure the IM is financially and substantively independent from any soliciting electric utility or affiliate thereof, complaining entity, and any potential bidder.

(2) The IM will report its findings with regard to the RFP process to the PSC.

(3) If the IM's conclusion is different from the conclusion of the LSE about the winning bidder(s), the IM and LSE may attempt to resolve such differences. The IM shall submit its independent evaluation to the PSC.

(4) As part of its contract with the IM, the PSC shall require the IM to enter into an agreement to keep all information confidential that pertains to the disclosure and use of any models analytical tools, data, or other materials of a confidential or proprietary nature provided or made available by the LSE in conjunction with the RFP.

D. The Role of the LSE

(1) Each LSE affiliate that intends to bid shall disclose publicly, in writing, the names and titles of the members of the affiliate's "Bid Team." Each LSE shall disclose publicly, in writing, the names and titles of the members of its "Evaluation Team." The Bid Team develops the affiliate's bid and, to assure fairness, is not involved, directly or indirectly, in the evaluation or selection of bids. The Evaluation Team evaluates bids, selects the successful bidder and, to assure fairness, is not involved, directly or indirectly, in the development of the affiliate's bid.

(2) Each LSE and bidding affiliate shall ensure that the Bid Team and the Evaluation Team have completely distinct personnel, and that any member of either do not engage in any communications, either directly or indirectly, regarding the RFP or the competitive bidding process. For bidder and PSC assurance, the LSE and bidding affiliate shall execute an acknowledgement that the LSE and affiliate have not and will not in the future so communicate, other than to submit and receive the bid at the appropriate time. The Bid Team and Evaluation Team may communicate as part of a bidding technical conference of which potential bidders or all actual bidders, if bids have already been submitted, are given adequate notice and opportunity to attend.

(3) The Evaluation Team shall report to the IM, any contact or communications by any bidder, including the Bid Team, and advise the bidder that any future contact must be directed to the IM. Bidders and the Evaluation Team may communicate as part of a bidding technical conference of which potential bidders or all actual bidders, if bids have already been submitted, are given adequate notice and opportunity to attend.

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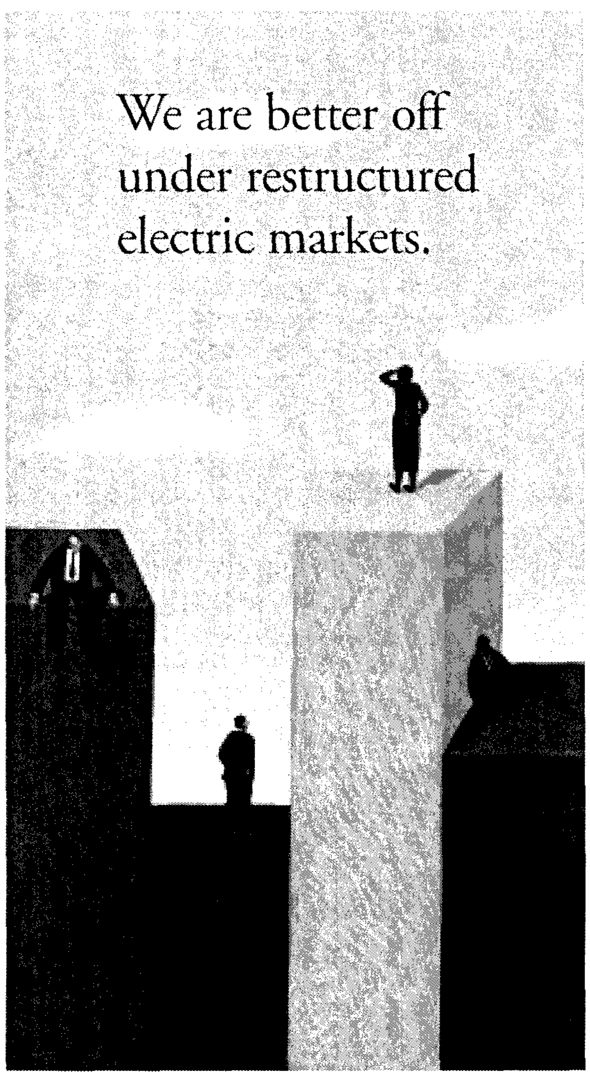
THE FALLACY OF HIGH PRICES

BY HOWARD J. AXELROD, PH.D., DAVID W. DERAMUS, PH.D., AND COLLIN CAIN, M.SC.



Since the Federal Energy Regulatory Commission (FERC) first issued Order 888[1] more than a decade ago, the restructuring of electricity markets, both at the wholesale and retail level, has provided significant benefits to electricity customers. Unfortunately, rising retail electricity rates, resulting from sharp increases in fuel prices and, in restructured states, the end of years of artificially capped rates, have caused consternation among consumers, which in turn has raised the ire of politicians, some of whom are demanding a return to traditional models of rate-of-return regulation.

Yet, despite the headlines, our research—and that of several others—has shown that wholesale competition has been successful, especially in markets in the eastern United States, and will foster lower, more stable electric prices over the long term than a retreat to traditional rate regulation.

How can this assertion be reconciled with recent rapid increases in electricity prices, particularly in areas of the country where restructuring has been implemented? The answer is that consumers, politicians, and even some regulators have focused far too much on the shorter-term independent system operator (ISO) market-clearing prices and not enough on portfolio-derived prices and long-term trends. Just as one day's change in the stock market should not be the basis of a comprehensive investment strategy, short-term price increases brought about by unprecedented increases in the prices of fossil fuels, as well as the removal of price caps that kept retail electric rates at unsustainably and artificially low levels for years, do not negate the real benefits that wholesale competition has provided.

Analyzing the benefits of competitive electricity markets is a challenging exercise, not because the benefits are small but because the restructuring process in this industry has been so complex, and because rate caps and changing fuel prices obscure the effects of increased competition. Restructuring efforts undertaken in different states and regions were disjointed, applied to different ratepayers at different times, and were fraught with negotiating and horse-trading over rate discounts, stranded cost recovery, transition periods and so forth. Rate caps and discounts kept retail prices low for varying periods of time, while wholesale prices followed volatile fuel prices. In some states, rate caps ended just as fuel prices were rising to unprecedented levels.

Considering the recent sharp increases in retail electric rates, it is little wonder that many individuals have questioned the benefits of competition. To the average ratepayer in states that undertook restructuring, and to many a policymaker in those states who has failed to appreciate the meaning of a rate freeze, it must indeed seem that competition has been the cause of recent rate increases. As discussed further below, such a simplistic assessment of the performance of competitive electricity markets is bound to produce spurious conclusions. Any reasonable analysis must account for both fuel prices and rate caps, and must examine more direct measures of how the electricity industry has been affected by greater competition.

Pay Now or Pay Later

The process of industry restructuring was not a magic wand that, once waived, instantly lowered electricity prices, although that appears to have been the expectation of at least some policymakers prior to the California crisis of 2000-2001. The price reductions that were achieved in some states immediately after restructuring generally were the result of settlement agreements among policymakers, market participants, and other parties; they were not themselves market prices. Indeed, short of a sudden drop in fuel prices, how could a move to competitive wholesale electricity markets result in an instant reduction in rates? Generally, one would not expect substantial rate reductions attributable to efficiency gains to occur immediately, but over a longer time horizon.

It is therefore all the more surprising, and encouraging, that in the relatively short time since electricity market restructuring has occurred, a number of tangible benefits have been realized. First, competition significantly increased efficiencies in the construction and operation of power plants. Since 1996, when restructuring was effectively initiated by passage of the Energy Policy Act, refueling outage times at nuclear power plants decreased dramatically, while operation and maintenance (O&M) expenses were lowered and capacity factors increased. Similarly, heat rates and capacity factors improved at coal-fired plants while O&M costs declined.[2] Average per-unit production costs, or procurement costs in states with competitive procurement, declined 1.1 percent per year between 2001 and 2004. In 2005, when oil prices increased 135 percent and natural-gas prices rose 210 percent, production/procurement costs rose only 5.6 percent.[3] Indeed, if restructured states had used the fuel-cost adjustment pass-throughs common in states with traditional rate regulation, rates would have been 15 percent higher.[4]

Second, competition has increased access to lower-cost generation, particularly in the organized markets. Numerous studies have documented this impact, with some studies finding as much as $15 billion in savings in the Eastern Interconnection.[5] Finally, competition has played an important role in shifting significant risks away from captive customers and on to those market participants best equipped to manage those risks—including the risks associated with cost overruns of new construction and risks of economic depreciation. Our studies have found that since restructuring began in the Northeast, the standard deviation of production costs, a measure of price volatility, has declined by 30 percent.[6] This finding is consistent with the observed volatility of real-time clearing prices, as the production costs we evaluated included a portfolio of both short- and long-term physical contracts as well as the financial instruments employed to mitigate market uncertainty.

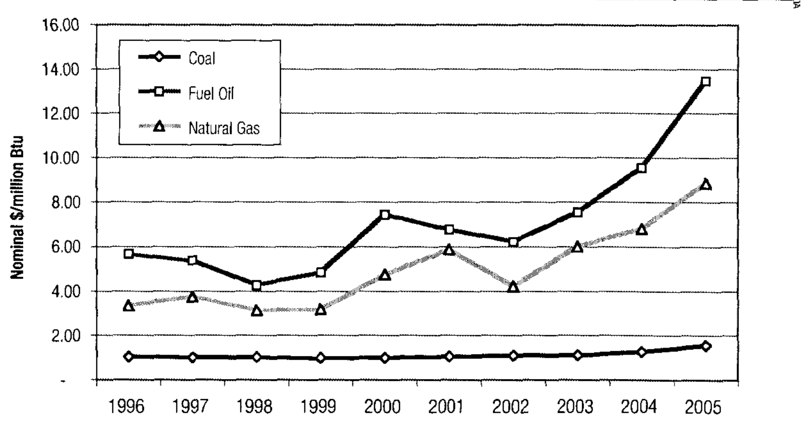
The path leading to these benefits of restructuring has been far from smooth. In fact, the development of robust competition in the electricity industry arguably has been delayed by numerous transition mechanisms imposed by regulators and politicians. Those mechanisms, especially multi-year price caps that "guaranteed" consumer savings, provided at best a temporary protection as world energy prices continued to rise. Moreover, those price caps, however well-intentioned, prevented consumers from gradually adjusting to market fluctuations typical of any industry. Not surprisingly, as if a dam burst, the end of those price caps, coupled with the sharp increases in fuel prices, has led to large price increases.

Market Timing

One of the difficulties in demonstrating the benefits of wholesale competition today is the high cost of fossil fuels, especially natural gas. In fact, the impetus for retail electric competition was, in large measure, low fossil fuel prices: Large commercial and industrial customers, in particular, sought to avoid paying higher rates based on utilities' embedded costs by gaining access to low-cost, gas-fired generation.

As the saying goes, "timing is everything." The gas glut of the 1990s, coupled with an inability to build any other type of generation because of environmental opposition in the Northeast, led to an increased reliance on new gas-fired »

Fig. 1 **Fossil Fuel Price Trends**



Note: EIA historical fuel price data. Fuel oil is No. 2 distillate. Natural gas is city gate price. Coal is bituminous coal.

generation to meet growing electric demand. When gas prices shot up beginning in 2002, so did wholesale market prices. Yet, despite the large fuel price increases, the data reveal that there have been tangible benefits from wholesale competition.

Fig. 1 presents fossil fuel trends between 1996 and 2005. Natural-gas prices (city gate) remained below \$4.00/MMBtu through 1999 and have been above that level since, with a rapid rise to near \$9.00/MMBtu in 2005.[7] Fuel oil prices have followed a similar pattern, reaching above \$13.00/MMBtu in 2005. Coal prices, while rising far less than either oil or natural gas, have nevertheless increased steadily since 2000.[8] Higher fossil-fuel prices have translated to an increase in wholesale electric prices. For example, in PJM, wholesale electric prices rose from about \$30/MWh in 1999 to above \$60/MWh in 2005.

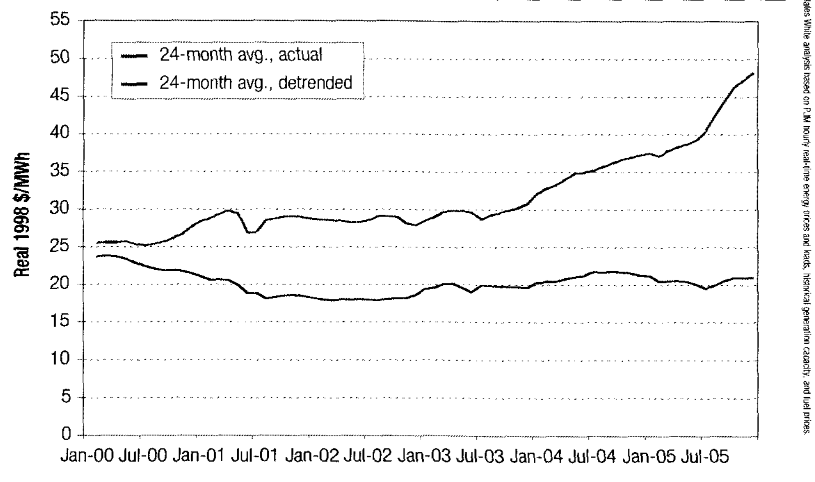
Yet, despite that increase in electricity prices, competition has wrung out significant benefits. Consider Fig. 2, which compares actual rolling 24-month average prices in PJM (adjusted for inflation) and prices "de-trended" to remove the impacts of higher fossil-fuel prices. (The de-trending analysis also controls for the effects of generation capacity reserve margin, peak demand, and extreme summer weather.) Wholesale electricity prices excluding the effects of fuel cost have decreased significantly since the inception of the PJM wholesale market in 1998. The average de-trended price for the last 24 months of the data period is 9 percent lower than that for the first 24 months. The restructuring process effectively has motivated power suppliers, now faced with the full force of competition, to operate far more efficiently.

To address possible arguments that an over-supply of generation caused these de-trended price decreases, our analysis also controlled for the impact of increasing generation capacity. Moreover, even if we had not controlled for this effect, if energy prices were indeed depressed by oversupply—*i.e.*, by the inability of some generators to sell at prices that covered their fully allocated costs, plus a return—this outcome nevertheless represents a dramatic change that is unequivocally a benefit of competition. Just as increased supply benefits consumers in other markets—whether groceries or automobiles—aggressive competition in the construction of new generation has been a boon for electricity consumers.

Under the model of traditional rate regulation, the full cost of investments, plus a return, are passed directly to consumers, with few exceptions. If electricity prices are lower because some producers are absorbing losses, this is a striking confirmation that, under competition, a significant component of long-term risk has been shifted away from consumers.

Our research provides several other important conclusions. First, fuel prices are pushing up electric rates everywhere. Customers, whether in restructured or non-restructured states, are seeing higher electric prices. In some cases, the end of artificial price caps is resulting in higher competitive procurement costs. In other states, fuel pass-throughs are resulting in increased

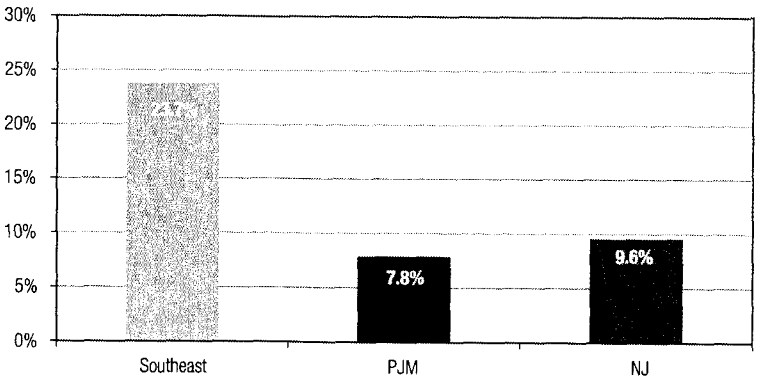
Fig. 2 **Actual and De-trended Wholesale Electricity Prices in PJM**



rates. Either way, customers are paying more for electricity. One recent study focusing on non-restructured states showed that customers in Louisiana have seen a 47 percent increase in electricity costs while customers in Oklahoma have seen a 38 percent increase.[9]

Perhaps even more interesting has been the effect of competition on regional price differentials. While a number of important factors—including fuel mix, labor costs, taxes, and cost of living—drive regional electricity prices, the gap between the PJM area, traditionally a high-cost area, and the Southeast, traditionally a low-cost area, has been shrinking. Our research shows that retail rates in five Southeastern states[10] rose 23.7 percent from 1998 to 2005, while rates in four "classic" PJM states[11] rose only 7.8 percent over that same period.[12] The 7.8 percent increase for the PJM states reflects continued rate caps for some customers in 2005, but the corresponding increase for New Jersey, which has had retail electricity rates set competitively since 2003, was just 9.6 percent (*see Fig. 3*).

FIG. 3 **CHANGE IN AGGREGATE RETAIL ELECTRICITY RATES, 1998-2005**



Source: EIA historical state retail electricity price data.

There are limits to how far one can extend such a comparative analysis of rates across different regions of the country. For example, the state of Maryland recently was engulfed in a significant political controversy when bids to provide standard-offer service to Baltimore Gas & Electric (BG&E) residential customers were 72 percent higher than the then current retail rates, which had been frozen since 1999 at a 6.5 percent discount to rates in effect since 1993. Obviously, if one were to compare Maryland's retail electric prices with prices in the Pacific Northwest (PNW), one would observe that PNW retail prices are significantly lower. Does that prove that there are not any benefits from competition? The answer is clearly no, since prices in the PNW reflect abundant, federally subsidized hydroelectric capacity not available in Maryland, which makes direct price comparisons between the two regions irrelevant and misleading.

To account for the difficulties inherent in a cross-regional comparison, we performed an econometric analysis of the effects of competition over a broad cross-section of the United States, using data for the years 1980 through 2004 for all states east of the Mississippi to estimate the effects of wholesale competition and state restructuring on the retail cost of electricity. We controlled for a number of factors influencing electricity prices, including generation mix, concentration of independent power producers, and capital costs. This specification of an econometric model allows us to derive a preliminary estimate of the benefits of wholesale competition and retail access, controlling for differences in fuel mix and other factors. Again, it is our view that a more robust estimate of the benefits of competition will require additional time, as many of the benefits of competition are inherently long-term in nature. Nevertheless, despite the relatively short time period since electricity restructuring was implemented, our econometric analysis indicates that the introduction of wholesale competition has resulted in an average reduction in the price of electricity by $6.50/MWh for all retail customers. Considering Maryland alone, as the state in which recent price increases arguably have caused the most political controversy, our analysis shows that the benefits of wholesale competition to Maryland consumers are more than $300 million per year.

Risk and Reward

Another benefit of wholesale competition has been the shift of significant risks from consumers to power producers. Prior to restructuring, if a regulated utility built too much generation (surplus capacity), most if not all of the costs would have been passed through to consumers. However, with a competitive wholesale market and competitive procurements by regulated distribution utilities—such as auctions for provider of last resort (POLR) or standard offer service (SOS)—significant risks are shifted away from captive customers to other market participants with the incentives and ability to assess and manage those risks. In particular, developers of new generation capacity assume the risk associated with that project coming in on time and on budget. In such a scenario, cost overruns and delays cannot simply be shifted to captive ratepayers as frequently occurs when incumbent utilities pursue "self-build" strategies under traditional cost-of-service rate regulation. In a competitive market, only those developers that can appropriately assess and manage the risks associated with building new capacity are able to earn a profit and attract capital; those who cannot are eventually forced to exit the market. Likewise, with a load auction for POLR service, wholesale suppliers can better insulate utility customers from fuel and purchased-power price risks, which otherwise would be passed through to customers along with the risks of capacity development. Such risk transfers stimulate new market entry and help drive down the ultimate costs to consumers.

A "Free" Market

In the event that it is not by now painfully obvious, competition is not a guarantee of low electricity prices. Rather, competition is a means for efficiently allocating scarce resources, sending appropriate price signals to guide investment and consumption decisions, and providing incentives for various market participants to act in ways that maximize social welfare. In a market economy, the main economic rationale for applying traditional rate-of-return regulation to any industry is in the case of a "natural monopoly," in which a good or service is provided most efficiently by a single firm. This characterization may apply to certain aspects of electricity transmission and distribution, but certainly does not apply to electricity generation. It is this contention, which we support strongly, that justifies efforts to restructure electricity markets.

We do not argue, however, that policymakers simply leave consumers, utilities, and other market participants to their own devices, even beyond the initial transitional phase of the restructuring process. Clearly, there needs to be a sufficient number of market participants or sufficiently low barriers to entry such that a market is likely to result in competitive prices and output rather than monopoly prices. Furthermore, we are strong proponents of institutional arrangements that monitor the behavior of market participants, enforce well-defined market rules, and ensure that the preconditions for competitive markets exist. Appropriate market rules and procedures should align market participants' incentives with broader policy goals of increasing efficiency, encouraging the appropriate amount and type of investment, and ultimately lead to reduced prices—and price volatility—for consumers.[13]

Our evidence shows that there have been significant benefits from electricity restructuring in the relatively short time since implementation. Not only has restructuring lowered wholesale and retail prices, it also has shifted significant risks away from customers to generators, which are better able to address those risks. There is no doubt that restructuring remains a work in progress, and that the transition to competition has had its painful moments. However, wholesale and retail competition should not be condemned based on the unprecedented increases in fossil fuel prices or rate shocks that were caused by political and regulatory pressures to guarantee benefits from day one.

Ultimately, for the full benefits of electric competition to be realized, the regulatory environment needs to become less politicized. Abrupt reactions to short-term circumstances, such as proposals for a return to traditional utility regulation, not only impede a rationale resolution of the challenges faced by policymakers and regulators, but also hurt ratepayers directly by creating uncertainty and increasing perceived investment risks, which ultimately lead to increased borrowing costs and higher rates. Given the volatility and uncertainty in fossil-fuel markets created by the conflicts in the Middle East and increasing demand in Asia, as well as uncertainty as to the ultimate policy resolution of important environmental issues such as climate change and mercury control, the last thing ratepayers need is to have politicized electricity markets.

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Endnotes

1. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Final Rule, April 24, 1996.
2. Putting Competitive Power Markets to the Test, Global Energy Decisions, 2005.
3. Based on research performed by Dr. Axelrod using the inflation adjusted weighted per unit production costs (FERC Form 1 data) for a sample set of Northeast utilities representing the PJM/NY/NE-ISOs structured markets.
4. Dr. Axelrod found when projecting 2004 Energy Information Administration (EIA) statewide electric price data for the Northeast using actual fuel price increases during 2005, as if fuel-related expenses were automatically flowed through, production costs would have been 15 percent higher than actual production costs as reported in the FERC Form 1 for 2005.
5. GED and PJM, ISO-NE, and NY-ISO State of the Market Reports.
6. Dr. Axelrod's analysis also found that the average standard deviation for the weighted production costs for the Northeast sample set was 0.45 percent for the pre-restructured period, 1996-2000, and 0.32 percent for the structured period 2000-2005.
7. Note that the natural-gas prices spiked following hurricanes Rita and Katrina at the end of 2005, with the average city gate price for October 2005 reaching above $12/MMBtu.
8. The coal-price series represents a national average including long-term contract prices. Spot prices have risen to a much greater extent than indicated. The spot price for Central Appalachian coal was above $60/ton, or $2.40/MMBtu, for most of 2005.
9. Electricity and Underlying Fuel Costs, Analysis Group, 2006.
10. Alabama, Georgia, Louisiana, Mississippi and South Carolina.
11. Delaware, Maryland, New Jersey and Pennsylvania.
12. Analysis based on EIA data.
13. While far from perfect, the best institutional arrangement devised to date to facilitate the development of electricity markets is the ISO/RTO framework, of which PJM arguably has been one of the best examples. It is thus all the more surprising—and rather alarming—to hear policymakers within PJM itself increasingly expressing opposition to electricity restructuring and competitive electric markets.

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Markets for Power in the United States: An Interim Assessment

*Paul L. Joskow**

The transition to competitive wholesale and retail markets for electricity in the U.S. has been a difficult and contentious process. This paper examines the progress that has been made in the evolution of wholesale and retail electricity market institutions. Various indicia of the performance of these market institutions are presented and discussed. Significant progress has been made on the wholesale competition front but major challenges must still be confronted. The framework for supporting retail competition has been less successful, especially for small customers. Empirical evidence suggests that well-designed competitive market reforms have led to performance improvements in a number of dimensions and benefited customers through lower retail prices.

1. INTRODUCTION

Despite longstanding academic interest (Joskow and Schmalensee (1983)) and some previous experience in other countries, comprehensive electricity sector restructuring and competition initiatives only began to be taken seriously by U.S. policymakers in the mid-1990s.[1] The first U.S. retail competition and restructuring programs began in Massachusetts, Rhode Island and California in early 1998 and

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1. Of course, wholesale power markets in which proximate vertically integrated utilities traded power on a daily and hourly basis subject to very limited regulation, have existed in the U.S. for many years. In addition, during the 1980s the Public Utility Regulatory Policy Act (PURPA) of 1978 stimulated the development of a non-utility power sector selling electricity produced primarily from cogeneration facilities and renewable energy facilities to local utilities under long-term contracts (Joskow, 1989). The Energy Policy Act of 1992 also removed important barriers to the broader development of unregulated non-utility generating facilities and expanded the Federal Energy Regulatory Commission's (FERC) authority to order utilities to provide transmission service to support wholesale power transactions. However, these developments largely reflected modest expansions of competition at the wholesale level built upon a basic model of regulated vertically integrated franchised monopolies.

spread to about a dozen additional states by the end of 2000. By that time several additional states had announced plans to introduce similar programs in the near future and a competitive market model for the electricity industry seemed to be sweeping the United States. The primary political selling point for competition in those states that were early adopters was that it would benefit consumers by leading to lower costs and lower prices in both the short run and the long run. The ideological commitment to competition as an alternative to regulated monopoly that characterized the Thatcher government's electricity sector privatization, restructuring and competition program in the United Kingdom (UK) was not a powerful force driving these reforms in the U.S. Indeed, the vast majority of the states that have implemented comprehensive wholesale and retail electricity competition initiatives cast their electoral votes for Al Gore in 2000 and John Kerry in 2004 and neither President Bush nor many of the states that gave him his greatest support have been strong supporters of comprehensive electricity sector restructuring and competitive market initiatives.[2]

The Federal Energy Regulatory Commission (FERC) supported the development of competitive wholesale markets during both the Clinton and Bush administrations. In 1996 FERC adopted rules specifying new requirements for transmission-owning utilities to make available open access transmission service tariffs (Order 888) and provide information about the availability and price of transmission service on their networks (Order 889). In late 1999 FERC embraced a more aggressive restructuring and wholesale market institutional change agenda in its Regional Transmission Organization (RTO) rule (Order 2000). It used various carrots and sticks to induce utilities and state regulators to adopt an aggressive restructuring and competition agenda.

However, the California electricity crisis of 2000-2001 (Joskow (2001)), concerns about market power problems there and elsewhere, phantom trading and fraudulent price reporting and accounting revelations, Enron's bankruptcy, and the financial collapse of many merchant generating and trading companies subsequently took the glow off of "deregulation." Rising wholesale market prices, resulting from rising natural gas and coal prices, closed or reversed the gap between the generation cost component of bundled regulated retail prices and the prices for equivalent generation services purchased in competitive wholesale power markets. This further reduced the interest of consumers and politicians in market-based prices, especially in those states with relatively low regulated prices. The slow pace at which retail customers switched to competitive suppliers in those states that adopted retail competition programs was disappointing and in turn led to a declining number of competitive retail supply options for residential and small commercial customers in many of those states.

Since the year 2000 no additional states have announced plans to introduce competitive reforms and several states that had planned to implement

2. When President Bush was Governor Bush he did support a comprehensive restructuring and competition program in Texas.

reforms have delayed, cancelled or significantly scaled back their electricity competition programs. Moreover, FERC's efforts to promote a competitive wholesale restructuring and competition model with a small number of RTOs covering large regions of the country and meeting stringent criteria for market design, geographic scope and independence confronted increasing political opposition after 2000. FERC found itself at war with many states in the Southeast and the West as they resisted its efforts to expand wholesale market and transmission institutions that it had identified as being necessary to support efficient competitive wholesale markets in all regions of the country. FERC's proposed Standard Market Design (SMD) rule issued in 2002 created enormous controversy and was withdrawn entirely in July 2005. The pressure from FERC to implement fully and effectively the creation of RTOs pursuant to Order 2000 appears to have receded as well. Re-integration of generation with transmission and distribution has begun to occur in a few states. Even the Cato Institute has lost patience with competitive reforms in electricity and appears to see merit in returning to the good old days of regulated vertically integrated utilities (Van Doren and Taylor (2004)). At the same time, most of the states in the Northeast, a few in the Midwest, and Texas, appear to be committed to moving forward with the development of competitive wholesale and retail markets and to making them work well, though the strength of the policy commitment to competitive electricity markets may have declined in these states as well.

After nearly 25 years of federal and state restructuring, regulatory reform and deregulation initiatives affecting almost every U.S. industry that had been subject to price and entry regulation prior to 1980, the deregulation policy ship appears to have run aground as it tries to lead the U.S. electric power industry along a path to competition. What is the problem? Are things as bad as opponents of competition suggest? Or does it depend on whether one looks at the glass being half empty or half full? What needs to be done to fix the problems that are really there to make a competitive model more attractive?

One of the challenges associated with providing objective answers to these questions for the U.S. is the lack of any comprehensive assessments of the effects of these reforms on costs, prices, innovation, and consumer welfare of the type that has been done, for example, for the UK (e.g. Newbery and Pollitt (1997), Domah and Pollitt (2001)). This kind of counterfactual analysis is difficult to do well under any circumstances. It is especially challenging when the data available to compare performance under regulated and competitive regimes is extremely limited, as is the case in the U.S. In this paper, I offer an array of "fragments of evidence" to illuminate what we know and what we don't know about the effects of competitive reforms on various performance indicia for the electricity industry in the United States to date. I examine the evolution and effects of both wholesale and retail competition reforms. I view this as an interim assessment because the restructuring and competition program for the electricity sector in the U.S. is clearly incomplete and a work in progress.

2. EVOLUTION OF NEW WHOLESALE MARKET INSTITUTIONS

The foundation of any well-functioning competitive electricity market system (with or without retail competition for all end-use customers) is a well-functioning wholesale market and supporting transmission network operating and investment institutions. Wholesale electricity markets do not design themselves but must be designed as a central component of any successful electricity restructuring and competition program. The U.S. electricity sector's legacy industry structure built upon a large number of regulated vertically integrated monopolies and nearly 150 network control areas was not conducive to creating well functioning competitive wholesale and retail electricity markets (Joskow and Schmalensee (1983), Joskow (2000, 2005a)). However, unlike England and Wales, Norway, Sweden, Spain, Australia, New Zealand, Argentina and other countries, the U.S. did not proceed with its wholesale and retail competition initiatives with a clear coherent blueprint for vertical and horizontal restructuring, wholesale market design, transmission institutions, or retail competition. There has been no federal legislation endorsing a comprehensive national electricity restructuring and competition policy. Horizontal and vertical restructuring has been much more limited than would have been ideal to support a smooth transition to competitive wholesale and retail markets. Rather than relying on a clear and coherent national reform policy with supporting federal legislation, as was the case for the earlier reforms applied to airlines, trucking, railroads, and telecommunications, electricity sector reforms have depended on regulatory initiatives taken by FERC under statutes that are 60 years old and by diverse and often inconsistent policies adopted by individual states.

2.1 FERC Takes the Lead

FERC has undertaken a number of initiatives to support the creation of competitive wholesale markets that are consistent with the diverse restructuring and competition policies that have been adopted by different states and associated political constraints on FERC's authority. Orders 888 and 889 issued in 1996 (and subsequently amended a number of times) required transmission owners to provide access to their networks at cost-based prices, to end discriminatory practices against unaffiliated generators and marketers, to expand their transmission networks if they did not have the capacity to accommodate requests for transmission service, and to provide non-discriminatory access to information required by third parties to make effective use of their networks.

FERC Order 2000 issued in December 1999 contained a new set of regulations designed to facilitate the "voluntary" creation of large Regional Transmission Organizations (RTO) to resolve what FERC perceived as problems created by the balkanized control of U.S. transmission networks and alleged discriminatory practices affecting independent generators and energy traders seeking to use the transmission networks of vertically integrated firms under

Order 888 rules.[3] Order 2000 also articulates several important goals for wholesale market institutions and represents a very significant step forward in the framework supporting the development of competitive wholesale electricity markets. These include (a) the creation of independent transmission system operators who will operate the transmission network reliably and economically without being influenced by the financial interests of generators, wholesale and retail markets of power; (b) the creation of large regional transmission networks with common transmission access and pricing rules and common wholesale market institutions to mitigate inefficiencies associated with the balkanized ownership and operation of transmission networks in the U.S.; (c) the creation of a set basic wholesale market institutions to support buying and selling power economically and for allocating scarce transmission capacity efficiently.

In mid-2002 FERC commenced a new rulemaking proceeding to consider a proposal for a "Standard Market Design" or "SMD" that would apply to all transmission-owning utilities over which FERC had jurisdiction. The proposed SMD rule enumerated a much more detailed set of wholesale market design requirements : (a) an Independent Transmission Provider (ITP) would be required to assume operating responsibility of all transmission systems, no matter how small; (b) a locational marginal pricing (LMP) based organized day-ahead and real time wholesale market design and congestion management system similar to those that were already in place in PJM and New York; (c) resource adequacy requirements that would obligate all load serving entities (LSEs) to make forward commitments for generating capacity and/or demand response to meet their forecast peak demand plus a reserve margin to be determined through a regional stakeholder process; (d) a regional transmission planning and expansion process would be implemented to identify transmission investment needs for interconnection, to meet reliability requirements, and that are economically justified but which are not being provided by the market; and (e) strong market monitoring and market power mitigation mechanisms would be required, including a proposed $1000/Mwh bid cap for energy and ancillary services in the day-ahead and real time markets, as well as bidding restrictions to deal with local market power problems.

2.2 Progress in the Development of Wholesale Market Institutions

Despite all of the political controversy surrounding these wholesale market reform initiatives, delays in implementing Order 2000 and the withdrawal of the proposed SMD rule in July 2005, a lot of progress has been made since 1996. As a direct result of FERC's "open access" Orders 888 and 889, all transmission-

3. *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999). Order 2000 technically makes participation in an RTO voluntary, but there are carrots and sticks available to FERC that initially created significant pressure for utilities to join RTOs. Order 2000 does not mandate a particular organizational form for an RTO, however.

owning utilities in the U.S. (either directly or through an independent system operator or ISO) now have made available reasonably standardized cost-based transmission service tariffs to support the provision of transmission service on their networks to third parties; provide easily available real time information to third parties about the availability and prices of transmission service on their networks; are required to interconnect independent power producers to their networks; must make their best efforts to expand their transmission networks to meet transmission service requests when adequate capacity is not available to accommodate these requests; must provide certain network support services, including balancing services, to third parties using their networks; and are required to adhere to functional separation rules between the operators of their transmission networks and those who generate and market electricity using that network to mitigate abusive self-dealing behavior. These developments were essential to support entry of independent generators, expansions in wholesale trade, and retail competition as discussed further below.

FERC's RTO rule has also led to important changes in the industry. Table 1 and Figure 1 indicate that as of mid-2005, over 50% of the generating capacity in the U.S. is now operating within an ISO/RTO context (including Texas which is not subject to FERC jurisdiction) and other areas of the country are moving forward slowly with some type of ISO/RTO model. Moreover, most of these ISO/RTOs either have adopted the basic wholesale market principles reflected in the FERC SMD or (in the case of California) are in the process of adopting these institutions or (in the case of Texas) giving them serious consideration (FERC (2005), p.52). I will discuss the attributes of the existing SMD markets in the Northeast presently.

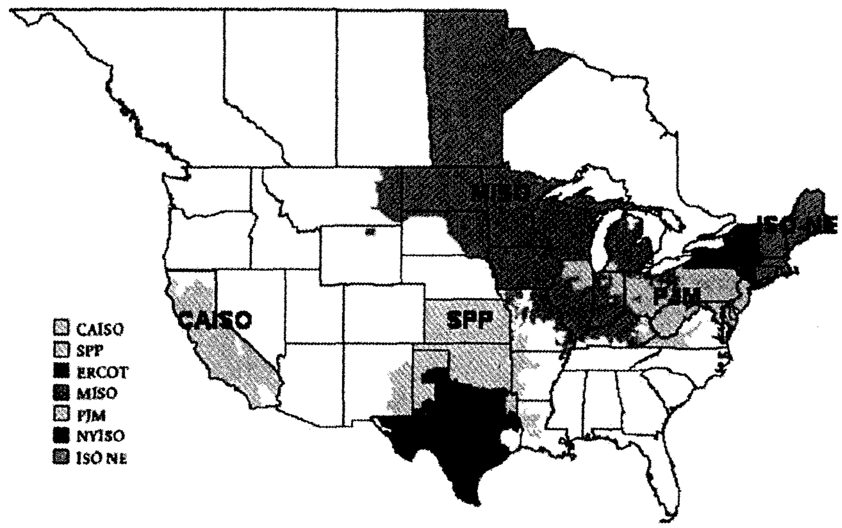
While FERC could not and did not order vertically integrated utilities to divest either their generating facilities or their transmission facilities to separate regulated from competitive lines of business, the combination of state initiatives

Table 1. Independent System Operators and Organized Wholesale Markets 2005

System Operator	Generating Capacity (MW)
ISO-New England (TRO)	31,000
New York ISO	37,000
PJM (expanded) (RTO)	164,000
Midwest ISO (MISO)	130,000
California ISO	52,000
ERCOT (Texas)	78,000
Southwest Power Pool (RTO)*	60,000
ISO/RTO Total	552,000
Total U.S. Generating Capacity	970,000

Sources: Individual ISO web pages and U.S. Energy Information Administration (EIAa) (various issues)
*Organized markets being developed.

Figure 1. ISOs and RTOs in the United States 2005



Source: U.S. Federal Energy Regulatory Commission (2005), p. 52.

and market opportunities has led to a considerable amount of restructuring of the ownership of existing generating plants. In 1996 there was about 750,000 Mw of utility-owned electric generating capacity in the U.S. of which investor-owned utilities (IOUs) accounted for about 580,000 Mw. After 1996, about 100,000 Mw of generating capacity was divested by IOUs and another 100,000 Mw transferred to unregulated utility affiliates to compete in the wholesale market. Moreover, between 1999 and 2004 about 200,000 Mw of new generating capacity was completed, about 80% of which was accounted for by unregulated generating companies (independent power companies and unregulated affiliates of utilities). See Table 2. More new generating capacity entered the market between 2001 and 2003 than in any three year period in U.S. history (FERC (2005), p. 59). Indeed, there was so much entry (and so little exit) that by 2003 there was excess generating capacity in most regions of the country. By 2004 over 40% of the power produced by investor-owned companies in the U.S. (i.e. excluding federal, state, municipal and cooperative generation) came from unregulated power plants, up from about 15% in 1996. After a decline in market liquidity following Enron's collapse, during 2004, trading in financial electricity products increased by a factor of ten (FERC (2005), p. 63).

The wholesale market design architecture articulated by FERC in its proposed SMD rule is also spreading, despite all of the controversy surrounding it and FERC's withdrawal of its proposed mandatory SMD rule. The primary features of this wholesale market design, built around a bid-based security

Table 2. New U.S. Generating Capacity (MW)

Year	Capacity Added (MW)
1997	4,000
1998	6,500
1999	10,500
2000	23,500
2001	48,000
2002	55,000
2003	50,000
2004	20,000
2005 (through May)	2,000
Total	Mw 220,000

Source: U.S. Energy Information Administration (EIAa and EIAb) (various issues).

constrained dispatch framework with locational or "nodal" pricing (LMP), has been or is being adopted in most of the regions that have created ISOs to operate regional transmission networks (SPP and Texas are the notable exceptions, although a nodal pricing system is being considered in Texas; FERC (2005), p. 52; *Megawatt Daily*, August 19, 2005, page 7). The SMD markets effectively integrate day-ahead, hour-ahead and real time energy prices, determined through a uniform price multi-unit auction framework, with the allocation of scarce transmission capacity. This makes the price of congestion quite transparent since it is reflected in the differences in locational spot energy prices in a way that reflects the physical attributes of the transmission network. Administrative rationing of scarce transmission capacity through the use of Transmission Line Relief (TLR) orders is, in principle, unnecessary, since scarce transmission capacity is rationed by prices and willingness to pay rather than through inefficient pro-rata administrative curtailments. Spot prices for energy reflect the marginal cost of congestion at each location on the network, and in New England and New York they reflect the marginal cost losses as well. Locational prices adjust smoothly to changes in supply and demand conditions on the network consistent with changes in the network's physical constraints. The creation and auctioning of Financial Transmission Rights (FTRs) that reflect the feasible set of allocations of generation to meet demand consistent with network transmission and related reliability constraints provides opportunities for market participants to hedge variations in congestion costs (Hogan (1992), Joskow and Tirole (2000)) and provide the financial equivalent of firm transmission service.

2.3 Attributes of SMD Markets Operating in the Northeast

The operation of the SMD markets can be illustrated with some examples from New England and New York. In New England the flow of power is typically from North to South, with import constraints into Boston and Southeastern Connecticut under certain supply and demand conditions and export constraints

Table 3. Day-Ahead Nodal Prices in New England

July 19, 2005, Hour 17
Load Zones Averages
$/MWH

Load Zone	Average Hour Price
Maine	130.56
New Hampshire	159.34
Vermont	195.65
Massachusetts (NE)	321.55
Massachusetts (SE)	162.12
Massachusetts (WC)	161.14
Rhode Island	142.44
Connecticut	165.96

Source: ISO New England Data Archive, http://www2.iso-ne.com/smd/operations_reports/hourly.php?warp=1.

from Maine and Rhode Island to the rest of New England. There are typically significant imports from Canada[4] and more limited imports and exports from and to New York. The associated transmission interconnection facilities are often congested as well. The introduction of an LMP-based wholesale market system has made this congestion transparent, yields associated price signals and facilitates the efficient allocation of scarce transmission capacity. In 2004, the average day-ahead LMP at the border between New Brunswick and Maine was about $53/Mwh and the average LMP in Connecticut was about $62/Mwh. The price difference reflects network congestion and thermal losses. The 17% difference in prices may not seem like much and perhaps not worth the effort. However, the annual average locational prices hide significant variations over time and across generation nodes as supply and demand conditions change. For example, Table 3 displays the average prices aggregated for each New England load zone for hour 17 on July 19, 2005, a hot day when the peak demand in New England hit a new record. It is evident that the price in Boston (NE Massachusetts) is two and a half times the price in Maine, reflecting import congestion into the Boston area. The zonal prices are much higher in Boston than in Connecticut at this hour even though on average during the year, Connecticut tends to be more congested than Boston. This shows that variations in spot prices for power reflect the fact that congestion patterns can change from one hour to another.

The price differences in New York State between New York City and Upstate New York are much larger than those observed for New England. In 2004 energy prices in New York City average nearly $90/Mwh while the average energy price in upstate New York was about $50, reflecting the import constraints into New York City and the high costs of the generating units located in the City (New York ISO (2005), p. 8).

4. Imports from outside the U.S. account for a very small fraction of aggregate U.S. electricity supplies.

2.4 Market Power and Its Mitigation

The development of competitive wholesale markets in the U.S. has been heavily influenced by concerns about market power. The potential for market power to be a particularly severe problem in electricity markets was recognized many years ago (Joskow and Schmalensee (1983), Chapter 12). It arises as a consequence of transmission constraints that limit the geographic expanse of competition, generation ownership concentration within constrained import areas, the non-storability of electricity, and the very low elasticity of demand for electricity (Joskow (1997), Borenstein (2002)). Generator market power was a serious problem for several years following the launch of the privatization, restructuring and competition program in the UK (Wolfram (1999)). Concerns about market power in the U.S. were reinforced by the events in California in 2000-2001 (Borenstein, Bushnell and Wolak (2002), Joskow and Kahn (2002)) where market power and the exploitation of market design imperfections contributed to the explosion in wholesale prices beginning in June 2000.

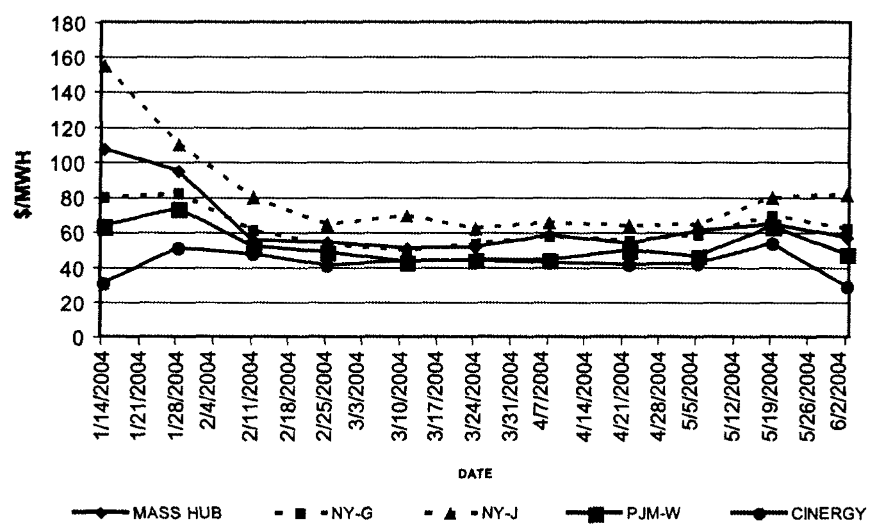
Market power monitoring and mitigation has been a central focus of FERC's wholesale market policies. However, despite all of the concerns about market power, the wholesale markets in the Northeast appear to be very competitive based on a variety of structural, behavioral and performance indicia (New York ISO (2005), pp. iii, vii; ISO New England (2005), pp. 98-106; PJM (2005), pp. 48-67). The primary exceptions emerge when supply and demand conditions lead to transmission constraints that create small "load pockets" within which the supply of generation is highly concentrated. However, market monitoring and mitigation protocols appear to have been reasonably successful in mitigating the ability of suppliers to exercise significant market power in these situations as well. Indeed, these measures may have been too successful, constraining prices from rising to competitive levels when demand is high, capacity is fully utilized, and competitive market prices should reflect scarcity values that exceed the price caps in place in the SMD markets (Joskow and Tirole (2005a)), a subject to which I shall return presently.

2.5 Intertemporal and Locational Price Convergence

Electricity is non-storable and supply and demand must be balanced with the ultimate in just in time production. This leads to significant volatility in spot market prices. However, the ability of suppliers and consumers to respond to large changes in real time prices is limited. This is especially true for suppliers or consumers in neighboring control/market areas. Many economic decisions in electricity markets are based on forward price signals in the hour-ahead, day-ahead, and longer forward markets. Market power is also more difficult to exercise in forward markets, making it attractive to move more price commitments into forward markets. Price convergence (intertemporal trading profits are arbitraged away) between the day-ahead, hour-ahead and real time markets is an important indicator of market performance. Price convergence in the SMD markets is reasonably good and has improved over time as these markets have been refined. Well designed virtual bidding opportunities can and have helped to improve price convergence and improve market efficiency (New York ISO (2005), pp. 10-16; ISO-New England (2005), p. 49)

Because the ISOs in the Northeast have adopted similar market designs, the integration of these markets has been facilitated and barriers to trade between these markets continue to decline, though "seams" issues continue to be an area where more work is needed (New York ISO (2005), pp. 66-73). The data in Figure 2 have been assembled to provide a simple picture of the interaction between these regional market areas as supply and demand conditions change. Figure 2 displays the day-ahead peak period (16 day-time hours on weekdays) prices for power at the Massachusetts hub, New York City (NY-J), the New York Hudson Valley (NY-G), the PJM West hub, and the Cinergy hub in the Midwest, for several days during the first six months of 2004. These hubs are all interconnected and power can be traded between them. If there were no congestion, no losses, efficient transmission pricing, and no institutional barriers to trade across these areas the prices would be equal to one another. In other words the Law of One Price would prevail. The general patterns of power flows in the Northeast are from the Midwest toward the East and from the North (Quebec, New Brunswick and Maine) to the South. New York City and Long Island are more frequently import constrained by transmission and related reliability constraints than other areas in the Northeast. It should be clear from Figure 2 that the Law of One Price does not prevail in Eastern electricity markets.

Figure 2. Day-ahead Peak Period Prices (2004) $/MWH



Source: Megawatt Daily, The McGraw-Hill Companies, (various issues).

The data in Figure 2 should be read starting at the far left with the locational day-ahead prices for mid-January 2004. It was extremely cold in the Northeast at this time, with temperatures falling to their lowest levels in over 50 years. As a result, demand for both natural gas and electricity were unusually high for this time of year. The electricity market in New England in particular was severely stressed despite the fact that peak demand was significantly lower than the quantity of installed capacity. Many generating plants were out of service due to routine maintenance, weather related problems, and the allocation of gas supplies between electricity generation and other uses (New England ISO (2004), FERC (2005), pp. 13-23). The demand for imported electricity into the Northeast from the Midwest increased and transmission capacity from the Midwest to the East became congested. We can see this in the separation of prices at various locations in mid-January. There was plenty of less costly generation in western Pennsylvania and the Midwest that could have served demand further east, but the transmission capacity to move the power east became constrained. Moving to the right in Figure 2 we see that as the weather returned to more normal levels as the year progressed the differences in locational prices compress significantly. New York City always has the highest prices because imports into New York City are frequently constrained by transmission limitations and some unique reliability considerations. The Mass Hub and Hudson Valley prices are about the same and often close to the PJM West prices. The Cinergy hub prices are always the lowest. Then as we move into June 2004 on the far right of Figure 2 we see the prices separate again as hot weather moves into the Northeast and demand for imported electricity rises again.

The markets in the Northeast and Midwest are clearly closely linked together, though spot energy prices exhibit locational differences as a result of congestion, losses, transmission service prices that exceed the marginal cost of providing transmission service (Joskow 2005b), and inefficiencies in the way these organized markets are linked together. Additional investment in transmission capacity, more effective utilization of the transmission capacity in place, more efficient pricing for transmission service, and enhanced integration and harmonization of the markets in New England, New York, PJM and MISO can reduce these price gaps and increase efficiency.

2.5. Wholesale Prices and Other Performance Indicia

It is difficult to measure the effects of the changes in wholesale market structure and institutions on wholesale market prices in the Northeast and Midwest since the mid-1990s when the reforms began. The wholesale markets that existed in 1996 were essentially "excess capacity" markets involving trades of electric energy between vertically integrated utilities which relied on regulated tariffs and captive retail customers to secure the capital costs for these facilities. Moreover, fuel prices, especially natural gas prices, have escalated dramatically since 1996 and hundreds of thousands of megawatts of unregulated generating capacity must

Table 4. Average Real Time Electric Energy Prices in New England Adjusted for Fuel Price Changes

	$/MWH	
Year	**Actual**	**Adjusted for Fuel Prices**
2000	45.95	45.95
2001	48.60	43.03
2002	46.55	37.52
2003	53.40	43.51
2004	54.44	43.33

Source: ISO New England (2005)

cover both their capital and operating costs through the sales of energy, ancillary services and capacity in competitive wholesale markets. Congestion costs are now transparent and revealed by differences in locational prices while they were once hidden in redispatch and unit commitment costs. There are some fragments of evidence about changes in wholesale market prices to consider, however.

A study comparing what prices would have emerged under cost of service regulation with the cost of buying that power in PJM's wholesale markets for three utilities in PJM, taking input cost changes into account, found that the cost of power purchased in PJM's wholesale market was lower than what the cost of that power would have been under continued cost of service regulation (Synapse Energy Economics (2004)). Wholesale market prices in New England, adjusted for changes in fuel prices, fell between 2000 and 2004 (See Table 4). Moreover, despite the fact that nominal wholesale market prices in the Northeast have risen along with fuel prices, the "all in" cost of power in the wholesale market (energy, ancillary services and capacity costs) between 2000 and 2004 was lower than the inflation adjusted regulated cost of generation service that was embedded to the regulated retail prices for many of the utilities in the Northeastern states in the late 1990s. For example, in the late 1990s, many northeastern utilities had average regulated costs of generation service in the 6 cent to 8 cent/kWh range (Joskow (2000)) or about 7 to 9.5 cents/kWh at current general price levels (without taking account of fuel price increases specifically). For the period 2002-2004, the all-in cost of power in the wholesale market in New York State outside of New York City and Long Island averaged about $50/Mwh. For New England the "all-in" price of wholesale power was about $50/Mwh over the period 2001-2004. In both cases this is significantly lower than the regulated cost of generation service embedded in retail prices prior to these reforms for many utilities in this region.

We should recognize, however, that cost-of-service regulation provided consumers with a hedge against fluctuations in fuel prices. In competitive markets the spot market price of electricity will reflect the marginal cost of the supplier that clears the market or the (much higher) value of unserved energy when the market is cleared on the demand side under "scarcity conditions" when capacity is fully utilized. Accordingly, if the marginal generating capacity that clears the market is natural-gas fired, the all-in market price of wholesale electricity will vary with variations in the price of natural gas, other things equal. Under cost-of-service regulation the all-in cost of generation service would be less sensitive to movements in natural gas prices in this case since the regulated costs of hydro, nuclear and coal-fired capacity would not vary directly with natural gas prices. Under cost-of-service regulation, natural gas price increases would have been reflected in retail prices in proportion to the fraction of generation accounted for by gas-fired capacity under cost-of-service regulation. Deregulation removes this hedge, making wholesale prices more sensitive to variations in the prices for fuel used by the marginal generating capacity that clears the market. If natural gas prices stay very high, it may turn out to be the case that in the short run, the costs of purchasing generation supplies out of competitive wholesale markets will be higher than the costs consumers would have paid under regulation as the rents associated with unregulated hydro, nuclear and coal capacity will now accrue to the owners of this capacity rather than to consumers as a consequence of the loss of this regulatory hedge. On the other hand, under regulation when there was excess capacity, prices rose to allow recovery of fixed costs while with competition excess capacity should lead to lower prices, other things equal. Consumers also were asked to pay for large generating plant construction cost overruns under regulation, while with competition it's the investors that bear construction cost overrun risks. We have too little experience to know how much these countervailing forces will affect generation service prices in the long run.

One of the benefits expected from the introduction of competitive wholesale markets was that it would provide incentives to improve the performance of the existing fleet of generating plants --- availability, non-fuel operating costs, heat rates (Joskow (1997)). Availability of generating capacity has increased over time in both New England and New York (ISO New England (2005), page 114; New York ISO (2005), p. 18). Equivalent availability factors increased significantly in PJM from 1994 to 1998 and have been roughly constant since then with some year-to-year variability (PJM (2005), p.168). Markiewicz, Rose and Wolfram (2004) find that the operating costs of generating plants fell more in states in the process of restructuring to support competition than in states which were not in the process of adopting restructuring programs. Bushnell and Wolfram (2005) find that divested generating plants and those subject to incentive regulation mechanisms improved their fuel efficiencies compared to their peers without high-powered incentives. Though the evidence is still limited, it tends to support the conclusion that competition has provided incentives to increase generating unit performance.

3. IMPROVING WHOLESALE MARKET PERFORMANCE

While there has certainly been a lot of progress made in creating good competitive wholesale market institutions, and there has been a lot of valuable learning from experience, there is still a lot more work to do. The necessary reforms go well beyond modifications in the details of Orders 888/889 as some have suggested is the appropriate focus of future FERC policy initiatives. Let me identify and discuss very briefly four areas where I think significant performance improvements need to be made.

3.1 Incentives to Invest in New Generating Capacity

Despite the enormous quantity of new generating capacity that entered service between 2000 and 2004, and the existence of excess capacity in most regions of the country, policymakers are now very concerned about future shortages of generating capacity resulting from retirements and inadequate investment. Many of the merchant generating companies that made these investments subsequently experienced serious financial problems and several went bankrupt. The liberal financing arrangements available to support these projects during the financial bubble years are no longer available and project financing for new generating plants is difficult to arrange unless there is a long term sales contract with a creditworthy buyer to support it. Rising natural gas prices have changed the economic attractiveness of the combined-cycle gas turbine technology that has dominated the fleet of new plants. The quantity of new generating capacity coming out of the construction pipeline is falling significantly (see Table 2). Very little investment in new merchant generating capacity is being committed at the present time, aside from wind and other renewables that can obtain favorable tax treatment and other financial and contractual incentives. System operators in the Northeast and California are projecting shortages and increases in power supply emergencies three to five years into the future, recognizing that developing, permitting and completing new generating plants takes several years. Unlike the situation in England and Wales, the U.S. does not have large amounts of mothballed capacity that can come back into service quickly as prices rise.

On the one hand, a market response that leads prices (adjusted for fuel costs) and profits to fall and investment to decline dramatically when there is excess capacity, is just the response that we would be looking for from a competitive market. For 25 years prior to the most recent market reforms the regulated U.S. electric power industry had excess generating capacity which consumers were forced to pay for through regulated prices. The promise of competition was that investors would bear the risk of excess capacity and reap the rewards of tight capacity contingencies, a risk that they could try to reallocate by offering forward contracts to consumers and their intermediaries. At least some of the noise about investment incentives is coming from owners of merchant generating plants who would just like to see higher prices and profits. On the other hand, numerous analyses of the performance of organized energy-only wholesale markets indicate that they do not appear to produce enough net revenues to support investment in new generating capacity in the right places and consistent with the administrative reliability criteria that are still applicable in each region. Moreover, while capacity obligations and associated capacity prices that are components of the market designs

Table 5. Theoretical Net Energy and Ancillary Services Revenue For A New Combustion Turbine Peaking Plant (PJM)

$/MW- Year	
Year	***Net* Energy and Ancillary Services Revenue**
1999	64,445
2000	18,866
2001	41,659
2002	25,622
2003	14,544
2004	10,453
Average	29,265
Annualized 20-year Fixed Cost ~ $70,000/Mw/year	

Source: PJM (2005)

in the Northeast produce additional net revenue for generators over and above what they get from selling energy and ancillary services, the existing capacity pricing mechanisms do not appear to yield revenues that fill the "net revenue" gap. That is, wholesale prices have been too low even when supplies are tight.

The experience in PJM is fairly typical. Table 5 displays the net revenue that a hypothetical new combustion turbine would have earned from the energy market plus ancillary services revenues in PJM if it were dispatched optimally to reflect its marginal running costs in each year 1999-2004. In no year would a new peaking turbine have earned enough net revenues from sales of energy and ancillary services to cover the fixed costs of a new generating unit and, on average, the scarcity rents contributed only about 40% of the costs of a new peaking unit. Based on energy market revenues alone, it would not be rational for an investor to investment in new combustion turbine or CCGT capacity in PJM. PJM has always had capacity obligations which it carried over into its competitive market design and in theory capacity prices should adjust to clear the market (Joskow and Tirole (2005b)). However, even adding in capacity revenues, the total net revenues that would have been earned by a new plant over this six year period would have been significantly less than the fixed costs that investors would need to expect to recover to make investment in new generating capacity profitable.

This phenomenon is not unique to PJM. Every organized market in the U.S. exhibits a similar gap between net revenues produced by energy markets and the fixed costs of investing in new capacity measured over several years time (FERC (2005), p. 60; New York ISO (2005), pages 22-25). There is still a significant gap when capacity payments are included. The only exception appears to be New York City where prices for energy and capacity collectively appear to be sufficient to support new investment, though new investment in New York may be much more costly than assumed in these analyses (FERC (2005), page 60). Moreover, a large fraction of the net revenue there comes from capacity payments rather than energy market revenues (New York ISO (2005), p. 23).

I have discussed elsewhere some of the regulatory, system operation and market imperfections that seem systematically to lead organized wholesale energy markets to produce inadequate incentives for new investment in generation consistent with prevailing engineering reliability criteria (Joskow (2005a), Joskow and Tirole (2005b)). The problems include: (a) price caps on energy supplied to the market and related market power mitigation mechanisms that do not allow prices to rise high enough during conditions when generating capacity is fully utilized to provide energy and operating reserves to meet reliability constraints. Under these conditions supply and demand should be balanced by responses on the demand side to high prices that reflect the value of lost load, producing significant competitive scarcity rents for generators; (b) price caps on capacity payments in the market designs that incorporate capacity obligations and capacity prices; (c) actions by system operators that have the effect of keeping prices from rising fast enough and high enough to reflect the value of lost load during operating reserve emergencies when small changes in system operating procedures can lead to very large changes in prices and scarcity rents needed to cover fixed costs; (d) reliability actions taken by system operators that rely on Out of Market (OOM) calls on generators that pay some generators premium prices but depress the market prices paid to other suppliers; (e) the absence of adequate spot market demand response to allow prices to play a larger role in balancing supply and demand under tight supply conditions; (f) payments by system operators to keep inefficient generators in service due to transmission and related constraints rather than allowing them to be retired or be mothballed, (g) regulated generators operating within a competitive market that have poor incentives to make efficient retirement decisions, depressing market prices for energy and (h) engineering reliability rules that have not been harmonized with market mechanisms and may implicitly impose costs of meeting reliability standards that are significantly greater than what consumers would be willing to pay in a well functioning competitive market.

The "resource adequacy" problems arising from imperfections in spot energy markets are now widely recognized by policymakers. FERC's proposed SMD rules contained requirements that system operators implement mechanisms to assure resource adequacy. Efforts are being made to reform capacity obligations and associated market mechanisms to try to deal with them (Cramton and Stoft (2005)). More could be done to reform spot energy markets to allow prices to rise to appropriate competitive levels when generating capacity is fully utilized, to expand demand side participation in the spot market, and to better harmonize reliability rules and reliability actions taken by system operators with market mechanisms.

3.2 Improve the Framework for Supporting Transmission Investment and Expanding Effective Transmission Capacity

As wholesale markets have developed congestion on the transmission network has increased significantly (Joskow (2005b, 2005c)). Investment in transmission capacity has not kept pace with the expansion in generating capacity and changes in trading patterns (Hirst 2004). Transmission congestion and related reliability constraints create load pockets, reducing effective competition among generators and leading policymakers to impose imperfect market power mitigation rules that create other distortions.

In addition to the effects of transmission congestion on wholesale power prices and the social costs of congestion, a congested transmission network makes it more challenging to achieve efficient wholesale market performance. Congestion increases market power problems and the use of highly imperfect regulatory mitigation mechanisms to respond to them. Congestion makes it more challenging for system operators to maintain reliability using standard market mechanisms, leading them to pay specific generators significant sums to stay in the market rather than retire and to rely more on OOM calls that depress market prices received by other suppliers (FERC (2005), pp. 6, 23, 61). In New England, the amount of generating capacity operating subject to reliability contracts with the ISO has increased from about 500 Mw in 2002 to over 7,000 Mw projected (including pending contracts) for 2005 (ISO-New England (2005), p.80).[5] These responses to transmission congestion undermine the performance of competitive markets for energy, exacerbate the net revenue problem discussed above, and lead to additional costly administrative actions to respond to market imperfections resulting from transmission congestion.

The existing framework for supporting transmission investment is seriously flawed. Regulatory responsibilities are split between the states and the federal government in sometimes mysterious ways (Joskow (2005b)). FERC initially supported a flawed "merchant investment" model (Joskow and Tirole (2005a)) and confused issues of who pays for transmission upgrades with questions about whether such upgrades would be mediated through market mechanisms (e.g. in return for FTRs) or regulatory mechanisms or a combination of both. Transmission investments driven by reliability considerations and transmission investments driven by congestion cost reductions are inherently interdependent but have been treated by FERC and some system operators as if they were completely separable (Joskow (2005c)). The U.S. does not even collect statistics on transmission investment and transmission network performance that are adequate to evaluate the performance of the network (U.S. Energy Information Administration (2004)). Despite promoting performance based regulation for transmission as provided for in Order 2000, there has been little progress in developing and applying a coherent incentive regulation framework in practice. Much of the increase in transmission investment that is reported to have occurred is associated with interconnections of new generators and associated network reinforcements to meet reliability criteria. There has been little if any investment in transmission facilities to increase interregional transfer capability.

5. FERC has ordered the ISO to replace these agreements with a locational capacity market mechanism built around an administratively determined "demand curve" for generating capacity. However, implementation has now been delayed until at least October 2006.

While the situation is improving with the adoption of more comprehensive transmission planning and investment processes in New England, PJM and the MISO, the transmission investment and regulatory framework has a long way to go before is will stimulate needed investments required to improve network performance and to create a transmission network platform that supports efficient competitive markets for power with less regulation and fewer administratively determined reliability contracts.

3.3 Continue to Reduce "Seams" Problems that Create Barriers to Trade Between Market Areas

The wholesale markets operating on the three synchronized U.S. transmission networks (Eastern Interconnection, Western Interconnection, and ERCOT (Texas)) are regional markets whose effective geographic expanses have grown over time. However, there remain opportunities to further reduce barriers to trade and to expand their geographic scope. The differences in wholesale market prices observed between different areas in the Northeast and Midwest (Figure 2) are partially a consequence of transmission network congestion. However, the price differences are also caused by regulated transmission prices that create an inefficient wedge between energy prices in different areas. They also reflect incompatibilities in the wholesale market mechanisms in different ISOs that limit trading between the spot markets operated in each area. Long distance trades in energy can still incur multiple transmission charges that include "pancaked" sunk cost allocations that make efficient trades uneconomical. Differences in the timing of the bidding and market clearing mechanisms and asymmetric treatment of generators in different control areas can further inhibit short-term trading opportunities and lead to inefficient allocation of scarce transmission capacity. The efforts by New England and New York and by PJM and the MISO to reduce these trading barriers are admirable and these efforts should be expanded to other regions.

3.4 Increase Demand Response

In markets for most goods and services when demand grows and supply capacity constraints are reached prices rise to ration demand to match the capacity available to provide supplies to the market. In electricity markets, however, as generating capacity constraints are reached, relatively little demand can be rationing by short term price movements and, instead, must by rationed administratively with rolling blackouts. The possibility of broader uncontrolled cascading blackouts and regional network collapses further exacerbates this problem, necessarily leads to regulatory requirements specifying operating reserves, operating reserve deficiency criteria and associated administrative actions by system operators to balance the system to meet voltage, stability and frequency requirements in an effort to avoid cascading blackouts (Joskow and Tirole (2005b)). The challenges faced by network operators to maintain system reliability and avoid non-price rationing of demand would be reduced if additional demand-side instruments were at its disposal. These include more customers who can see and respond to rapid changes in market prices and expanded use of price-contingent priority rationing contracts (Chao and Wilson 1987).

Too little demand side response has been developed to date. In New England, with a peak demand of over 26,000 Mw only a few hundred Mw is available to the system operator for use during power supply emergencies (ISO New England (2005), p.91). New York, with a peak demand of over 30,000 Mw has done better with about 1700 Mw of "quick" demand response (New York ISO (2005)). The demand response instruments that are available are poorly integrated with spot markets and are likely to have the effect of depressing prices inefficiently. Moreover, the prices that are paid for demand response or the prices that can be avoided by responding to price signals are too low compared to the long run cost of carrying generating capacity reserves to meet planning reserve margins. Improving demand response should be given higher priority in wholesale market design.

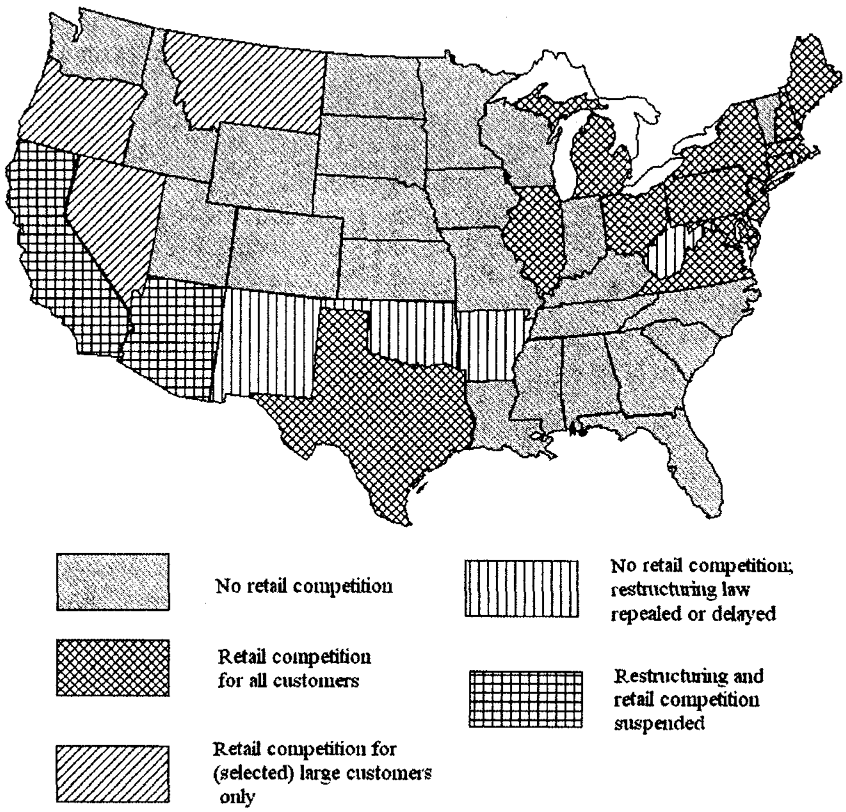
4. RETAIL COMPETITION

In the policy arena, the primary selling point for competition in electricity in most states has been the prospect for *retail competition* or *retail customer choice* to lead to lower *retail* electricity prices. My assessment of the status of retail competition among the states is displayed in Figure 3. All of the states, except for Texas, that have implemented and sustained comprehensive retail competition programs are in the Northeast and upper Midwest. These states had regulated retail prices that were among the highest in the U.S. in 1996 (Joskow (2000)). California suspended its retail competition program in 2001 as did Arizona (where it never really got started). Three states have programs that are limited to selected industrial customers. All of the other states either withdrew their existing plans to introduce retail competition after the California electricity crisis or never adopted a retail competition plan. There appears to be little interest today in those states without retail competition to introduce it and some pressure in states that have it to repeal it.

With a retail competition program, an electricity customer's bill is "unbundled" into regulated non-bypassable "delivery" component with a price P_R (transmission, distribution, stranded cost recovery, retail service costs to support default services) and a competitive component with a price P_C (generation service, some retail service costs, and perhaps an additional "margin" to induce customers to shop). The customer continues to buy the regulated delivery component from the local distribution company but is free to purchase the competitive component from competing retailers which I will refer to as retail Electricity Service Providers (ESP).

In most jurisdictions that have introduced retail competition programs, the incumbent distribution company is required to continue to provide regulated "default service" of some kind to retail consumers who do not choose an ESP

Figure 3. Status of retail competition and restructuring reforms 2005



Source: Author's assessments.

during a transition period of from five to ten years. The terms and conditions of default service vary across the states, but typically default service prices have been calculated in the following way. Regulators start with the incumbent's prevailing regulated cost of generation service. A fraction of this regulated generation cost component may be determined to be "stranded generation costs" that can be recovered from retail consumers over some time period and is included in the regulated price of delivery services P_R. The residual is then used to define the initial "default service" price P_C or the "price to beat" by ESPs seeking to attract customers from the regulated default service tariffs available from the incumbent utility. The value of P_C is then typically fixed for several years (sometimes with adjustments for fuel prices). After the transition period the default price is expected to equal at least the competitive market value of providing competitive retail services to consumers.

In many states the regulated default service price was either set or eventually fell below the comparable cost of power in the wholesale market. In some cases, rising wholesale prices caused by higher gas prices erased or reversed the gap between the default price and the wholesale price. For example, in Pennsylvania, PPL has a default price of 5.5 cents/Kwh for residential customers that is based on a formula defined when retail competition was initiated in Pennsylvania in 2000.[6] The forward *wholesale* price for power delivered at PJM West for Calendar year 2006 (16 hours per day for six days per week) was about 8 cents/kWh on August 23, 2005. PPL's default price is not scheduled to rise to market levels until 2010. Obviously, ESPs will find it difficult profitably to buy power at 8 cents and sell it at under 5.5 cents to attract customers away from default service.

4.1 Customer Switching Patterns

Most states that have introduced retail competition have experienced fairly similar and generally disappointing switching patterns. Relatively few residential and small commercial customers switch to ESPs and the migration from the incumbent's default service to competitive service for all but the largest customers has been very slow (Joskow 2005a). Larger industrial customers have been more likely to switch to ESPs and have done so much more quickly than residential customers.

To provide a typical example, Table 6 displays the retail switching statistics for Massachusetts, one of the first states to introduce retail competition, for February 2004 and May 2005. Retail competition was introduced for all customers in Massachusetts in early 1998, so consumers have had seven years to adapt to it. Only about 7% of the residential customers accounting for 6% of residential consumption have switched. There are few ESPs offering service to residential and small commercial customers active in the market. Over a similar period of time, over 50% of the residential customers switched to competing suppliers in England and Wales and there are several competing retail suppliers offering service to residential (domestic) customers there. Switching in Massachusetts has been greater among small, medium and large commercial customers, with the largest electricity consumers in each category being more likely to switch. After seven years of retail competition, only 8% of the total retail customers accounting for 34% of electricity consumption have switched to competitive suppliers. However, switching among all classes of customers (and the number of ESPs seeking customers) now seems to be increasing since the regulated default service (called standard offer service in Massachusetts) ended in March 2005 and all default service prices began to reflect wholesale market values. This appears to be the reason that we see a big jump in switching activity between February 2004 and May 2005.

6. *Megawatt Daily*, August 18, 2005, pages 1 and 10.

Table 6. Retail Competition in Massachusetts February 2004 and May 2005

Retail Choice Began March 1998

Customer Type	% of Load Served by ESP's February 2004	% of Load Served by ESP's May 2005
Residential	2.6	6.1
Small Commercial/Industrial	10.8	19.3
Medium Commercial/Industrial	17.0	22.2
Large Commercial/Industrial	48.3	63.3
Total	22.6	34.0

Source: Massachusetts Department of Energy Resources (2005)

Texas has had the most successful U.S. retail competition program as measured by customer switching activity. Retail competition began officially in Texas in January 2002, though there was a pilot program implemented before that and customers who had switched before the official program began could stay with the ESPs they had chosen. Texas adopted a retail competition program similar to that in the UK. Regulated default service was limited to smaller residential and commercial customers, the price for this service was set at (or above) wholesale market levels, the "price to beat" left an additional margin for competitive suppliers, and incumbents were given incentives to shift their retail customers to competitive suppliers. By June 2005 about 15% of the residential customers had switched to ESPs and the fraction continues to grow (Public Utility Commission of Texas (2005)). For commercial customers, 20% of the customers and 46% of the load had switched to ESPs by June 2005, while 38% of the largest customers, accounting for 63% of the load, had switched to an ESP. Virtually all of the largest customers have negotiated competitive contracts either with the retailing affiliate of their incumbent utility or an unaffiliated ESP. Unlike Pennsylvania, where the fraction of customers served by ESPS has declined over time (not the sign of a successful product), retail switching shows a monotonic increasing trend in Texas. Texas is also the state that has the largest number of active ESPs competing to sell service to retail consumers.

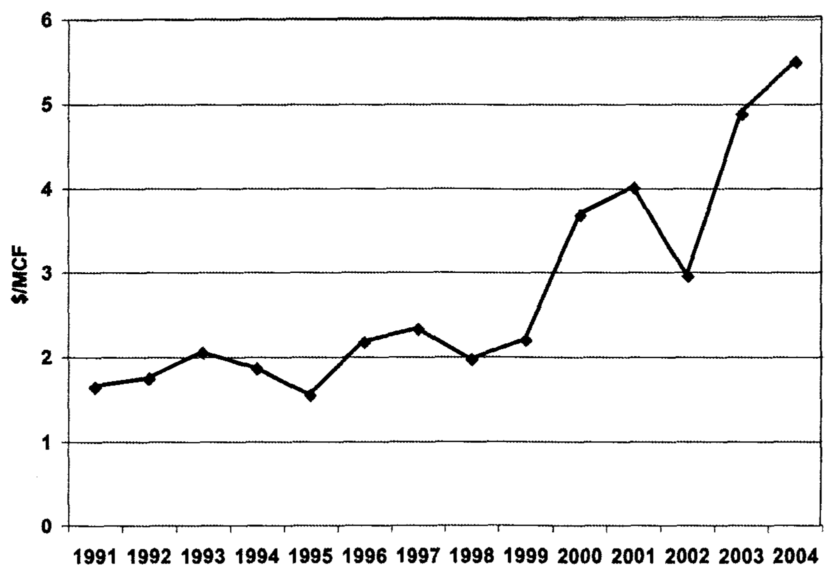
The biggest problem facing ESPs is "competition" from regulated default service and the unpriced option to go and return from regulated to competitive retail prices and back again that is often embedded in it. If regulated default service prices are set below the comparable wholesale market price of power, ESPs will not be able to compete for retail customers. Moreover, allowing customers that choose to take service from an ESP to return to a regulated tariff when wholesale prices are high, without being charged an appropriate price for this option, seriously undermines the development of retail competition. This leads to a very unstable customer base for ESPs, and undermines incentives for ESPs to enter into long term forward contracts or acquire generating assets to support their retail supply portfolios. While I remain unconvinced that residential and small commercial consumers are likely to benefit from retail competition, compared to simply relying on the local distribution company to buy power for them in the wholesale market, the worst of all worlds is the adoption of policies that rely on retail competition evolving but make it uneconomical for customers to switch to an ESP. Policymakers need to choose whether or not they really have faith in retail competition and adopt policies that either support its development if they do or rely instead on a wholesale competition model in which distribution companies procure power competitively if they don't.

5. RETAIL PRICE PATTERNS

The promise of lower prices was the political selling point for competition in most states. Policymakers in many states are asking whether or not competition is benefiting consumers through lower prices. We should be able to answer their questions. But lower compared to what? Lower than they were in 1996? Lower than they would have been if the regulated monopoly regime had continued? Lower in real dollars or nominal dollars? Policymakers were not particularly clear about the relevant comparisons as they were selling or opposing pro-competition reforms over the last decade. Given changes in fuel prices, demand, technology and environmental constraints, the only sensible comparison is between what prices are at a point in time under a competitive institutional framework and what they would have been if the prevailing regulated monopoly framework had continued. Unfortunately, this is a difficult counterfactual comparison to make. It is complicated by the large increase in natural gas prices (Figure 4) and the entry of almost 200,000 Mw of new mostly gas fired generation since 1998 (Table 2). Under a competitive model retail prices reflect the aggregation of competitive components (generation and retail supply) and regulated components (transmission and distribution). Moreover, since the industry structure and regulatory frameworks have varied from state to state, the answer to this question could very depend on variations in the nature of regulatory institutions and the performance of regulated firms in different states.

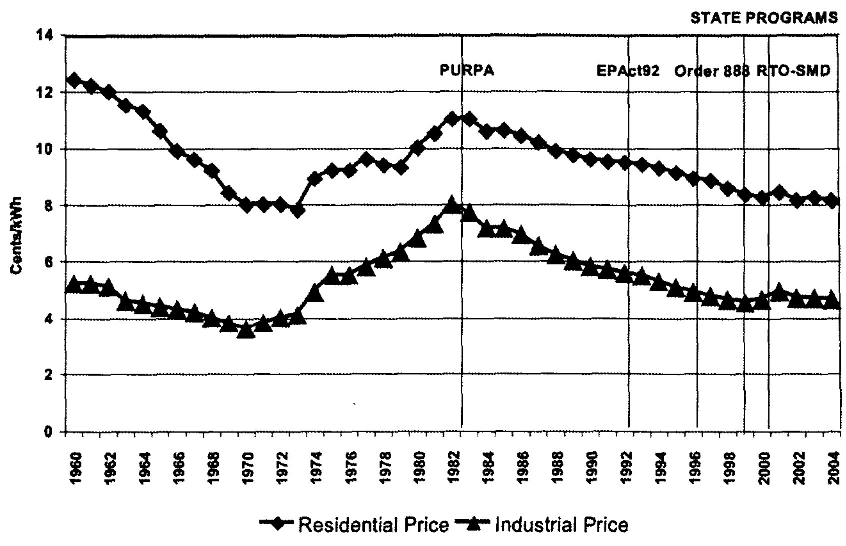
To place the analysis that follows in context, Figure 5 displays a time series of average *real* residential and industrial electricity prices from 1960 through 2004 for the U.S. as a whole. Average real U.S. electricity prices fell virtually continuously from the early 20th century until about 1972. The combination of rising inflation, rising nominal interest rates, the exhaustion of scale economies in generation, and large increases in fuel prices in connection to the oil shocks in 1973 and 1979 reversed this historical trend. As fuel prices, inflation and nominal interest rates began to fall in the early 1980s, real electricity prices began to fall as well (Joskow (1974, 1989)). While some trace the start of policy initiatives to promote competition to the implementation of PURPA in the early 1980s, it is widely believed that PURPA, as it was implemented in the states with the greatest enthusiasm for it, led to higher rather than lower retail prices (Joskow (1989)). Accordingly, it would be incorrect to conclude from Figure 5 that there is a causal

Figure 4. Average natural gas wellhead prices 1991-2004, $/MCF



Source: U.S. Energy Information Administration (EIAc, EIAd) (various issues).

Figure 5. Average real U.S. electricity prices 1960-2004 ($2000)



Source: U.S. Energy Information Administration (EIAd, EIAa) (various issues), nominal prices adjusted using the GDP deflator.

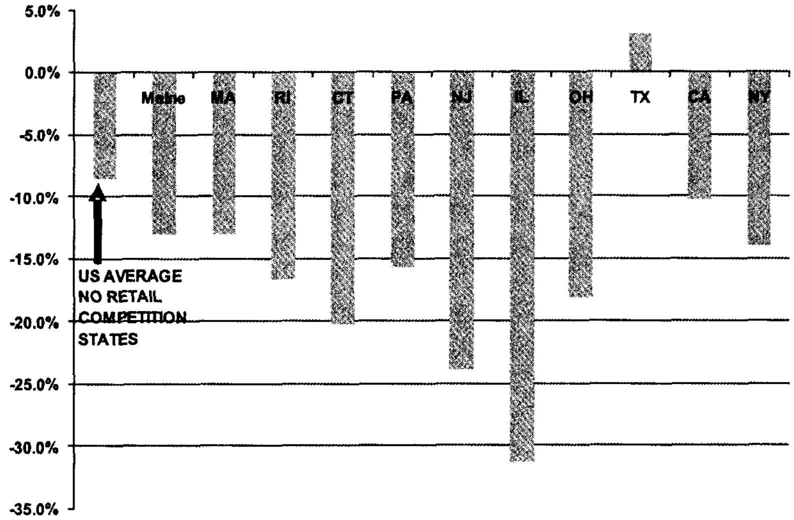
relationship between the implementation of PURPA and the renewed trend of lower real electricity prices. The major contemporary competitive initiatives began to be realized after 1996 with Orders 888 and 889, the retail and wholesale restructuring initiatives in California and several Northeastern states in 1998, the associated divestiture of regulated generating plants that became unregulated Exempt Wholesale Generators (EWG) as permitted by reforms contained in the Energy Policy Act of 1992, the entry of a large amount of new EWG capacity in many areas of the country following the state and federal reforms after 1996, and the subsequent FERC and state reforms that I have already discussed. There is certainly no noticeable dramatic change in the trend of average real U.S. electricity prices displayed in Figure 5 that can be readily associated with these post-1996 reforms. If anything, the rate at which real electricity prices fell seems to have declined as these reforms were implemented. Accordingly, the aggregate time series data alone tell us little about the effects of competition and regulatory reforms on the prices paid by consumers.

We can slice the data another way and compare the trends in retail prices in states that adopted retail competition reforms, often along with other restructuring reforms that supported the development of competitive wholesale markets, with the price trends in states that did not adopt such reforms. Figure 6 compares the changes in real residential electricity prices for states that introduced retail competition and those that did not between 1996 and 2004.[7] It is evident that real residential prices fell more in states that implemented retail competition programs than in those that did not. Only Texas shows an increase in residential prices. However, in light of the discussion in the last section, if the lower prices in retail competition states are due to competition reforms they are a consequence of the negotiations over stranded cost recovery, regulated default service pricing, lower wholesale market and perhaps reforms in the regulation of distribution networks rather than retail competition per se. This must be the case because so few residential customers have switched from regulated default service to service provided by competitive retail suppliers. Indeed, the states with the largest reductions in real prices (Illinois and New Jersey) had almost no residential switching. Moreover, Texas has had the greatest success with getting residential customers to switch to competitive suppliers and is the only retail competition state to exhibit an increase in real residential prices during this period of time.

Figure 7 displays the same information for industrial prices. Here the results are more mixed. There is no consistent pattern in the trends in real industrial prices for states that implemented retail competition compared to

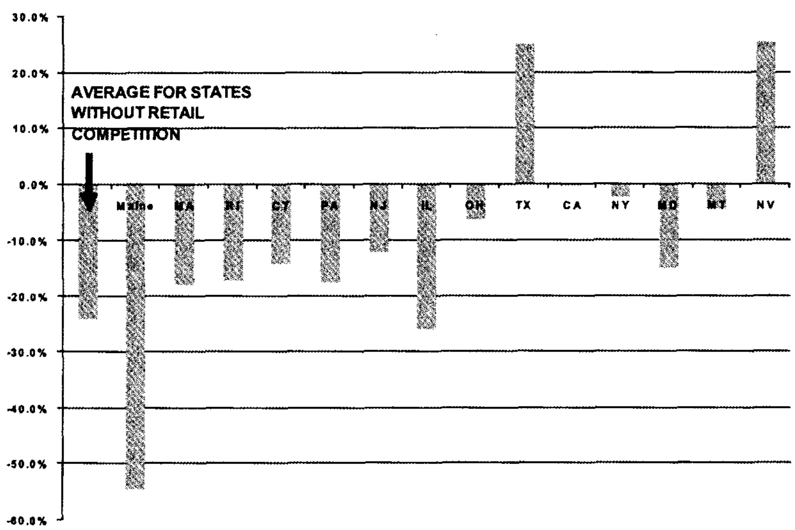
7. One important caveat to this and the analysis that follows should be noted. The retail price data may have imperfections. Reported retail price data ultimately rely on reports filed with the U.S. Energy Information Administration (EIA). It is fairly clear that it took some time for EIA to take full and appropriate account of the impacts of retail competition on the price data reported to them. However, by 2004 EIA seems to have solved these reporting problems so that the comparisons between 1996 prices before there was any retail competition and 2004 prices should be valid.

Figure 6. Changes in real residential prices with and without retail competition 1996-2004 (%)



Source: Calculated from U.S. Energy Information Administration (EIAa, EIAb, EIAd) (various issues), adjusted for changes in the consumer price index.

Figure 7. Changes in real industrial prices 1996-2004 with and without retail competition (%)



Source: Calculated from U.S. Energy Information Administration (EIAa, EIAb,EIAd) (various issues), adjusted for changes in the Consumer Price Index.

those that did not. Indeed, real industrial prices fell more on average in states without retail competition than in those states that introduced it for industrial customers. States like Nevada and Montana introduced retail competition for industrial customers in a way that provided little protection from changes in wholesale market conditions, while other states provided hedged default service prices of varying durations and with varying terms and conditions. Moreover, the generation mix and the associated effects of fuel prices on generation costs, entry of unregulated generators, and changes in wholesale market conditions varies from region to region.

We can begin to analyze the impacts of wholesale and retail market reforms on electricity prices in different states using additional time series and cross-sectional data that measure these variables and allow us to control for various cost drivers. The following analysis is what I believe is the first, admittedly crude, empirical analysis to examine more systematically the effects of cost drivers and competitive policy reforms on retail prices across states and over time. I view it as more of a systematic data analysis exercise than an effort to estimate a complete model of retail prices. It is a starting point that I hope will lead to more refined analyses.

I have collected a state-level panel data set covering the period 1970 through 2003[8] that includes variables measuring residential and industrial retail prices, various cost drivers, and variables measuring the intensity of various "deregulatory" initiatives, starting with PURPA. The data are discussed in more detail in the Appendix. In the spirit of Stigler and Freidland (1962), I estimate the following price equation for residential and commercial customers using state-level data for the periods 1970–2003 and 1981-2003 that include variables measuring cost drivers and those measuring various policy initiatives. The sample begins well before the introduction of the policy treatments so that the coefficients of the cost drivers should be well established.

$$\begin{aligned} P_{itj} = \beta_0 + \beta_1 RFC_{it} + \beta_2 HYDRO_{it} + \beta_3 NUCLEAR_{it} + & \\ \beta_4 RYield_t + \beta_5 SIZE_{it} + \beta_6 PURPA_{it} + \beta_7 EWG_{it} + & \\ \beta_8 RETAIL_{it} + \mu_i + \nu_t + \varepsilon_{it} & \end{aligned} \tag{1}$$

where:

i indexes states
t indexes years
j is either the residential price (r) or the industrial price (i)
μ_i is a state specific error
ν_t is a time specific error
ε_{it} is an iid random error

8. The data for some of the right hand side variables are not yet available for 2004 as this is written.

and the variables are defined as:

P: average retail residential or industrial price.

RFC: average real fossil fuel price per kWh of total electricity supplied in each state over time.

RYield: Real yield on electric utility debt over time.

HYDRO: share of total electricity supplied coming from hydroelectric generation in each state over time.

NUCLEAR: share of total electricity generation coming from nuclear plants in each state over time.

PURPA: share of total electricity generation coming from PURPA qualifying facilities (QF) in each state beginning with 1985.

EWG: share of electricity generated by unregulated generators in each state beginning in 1998.

RETAIL: a dummy variable indicating whether or not a state had introduced retail competition in a particular year — beginning in 1998.

Table 7. Residential Price Equations 1970-2003 (standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.51 (0.019)	0.51 (0.019)	0.48 (0.019)
HYDRO	-0.20 (0.077)	-0.16 (0.095)	-0.36 (0.099)
NUCLEAR	0.39 (0.054)	0.38 (0.056)	0.45 (0.056)
YIELD	0.042 (0.002)	0.043 (0.002)	0.047 (0.002)
SIZE	-0.13 (0.0044)	-0.13 (0.0048)	-0.11 (0.0063)
PURPA	0.43 (0.078)	0.42 (0.079)	0.61 (0.084)
EWG	-0.24 (0.058)	-0.23 (0.058)	-0.23 (0.057)
RETAIL	-0.24 (0.042)	-0.25 (0.042)	-0.21 (0.042)
R^2 (corrected)	0.74	0.61	0.62

Source: See text and appendix.

Table 8. Residential Price Equations 1981-2003 (standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.24 (0.031)	0.19 (0.032)	0.048 (0.029)
HYDRO	-0.064 (0.11)	0.125 (0.153)	-0.36 (0.137)
NUCLEAR	0.21 (0.071)	0.136 (0.073)	0.082 (0.056)
YIELD	0.06 (0.0046)	0.056 (0.0047)	0.027 (0.004)
SIZE	-0.18 (0.0077)	-0.21 (0.0088)	-0.1 (0.0089)
PURPA	0.22 (0.09)	0.122 (0.092)	0.288 (0.082)
EWG	-0.19 (0.054)	-0.16 (0.054)	-0.16 (0.048)
RETAIL	-0.24 (0.039)	-0.25 (0.038)	-0.126 (0.034)
R^2(corrected)	0.66	0.73	0.79

Source: See text and appendix.

Table 7 presents the regression results for the retail price model for residential prices for the period 1970 through 2003 using (1) generalized least squares, (2) state-specific fixed effects and (3) and state-specific fixed effects plus a time trend to correct for potential serial correlation. Table 8 presents the results for the same specifications for a shorter panel covering the period 1981-2003. Tables 9 and Table 10 present the same estimation results for industrial prices.

Let us look first at Tables 7 and 8 where the results for the residential price regressions are displayed. The results for the three alternative specifications and the two time periods are quite similar. For the residential price regressions the cost drivers generally behave as expected, recognizing that the fixed-effects regressions identify the coefficients from "within-state" variation over time. Increases in real fuel prices lead to higher retail electricity prices. More hydroelectric generation leads to lower retail prices. More nuclear capacity leads to higher retail prices reflecting the high capital costs of nuclear plants and their contribution to stranded cost recovery factors in states that introduced retail competition. Higher real interest rates also are associated with higher residential prices.

Turning to the policy variables, the more important is PURPA (QF) generation the higher are retail prices, consistent with the earlier literature (Joskow (1989)). The more important is unregulated wholesale market power supplies (EWG) the lower are retail prices. EWG generation has potential effects

Table 9. Industrial Price Equations 1970-2003 (standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.74 (0.019)	0.73 (0.02)	0.68 (0.019)
HYDRO	-0.264 (0.078)	-0.13 (0.10)	-0.535 (0.10)
NUCLEAR	0.20 (0.071)	0.22 (0.055)	0.42 (0.056)
YIELD	0.034 (0.0054)	0.034 (0.002)	0.043 (0.002)
SIZE	-0.4 (0.034)	-0.4 (0.035)	-0.3 (0.03)
PURPA	0.41 (0.08)	0.38 (0.081)	0.69 (0.083)
EWG	-0.26 (0.059)	-0.24 (0.059)	-0.22 (0.057)
RETAIL	-0.16 (0.043)	-0.17 (0.043)	-0.12 (0.042)
R^2 (corrected)	0.62	0.60	0.64

Source: See text and appendix

in both states with retail competition and those without it since EWG generation is a substitute for the generation a vertically integrated utility might produce from its own power plants. Note that there is substantial EWG generation in the Southeast where there is no retail competition. Finally, the coefficient on the retail competition dummy variable is consistently negative. The measured effect is that retail competition reduces retail prices on the order of 5% to 10% at the means of the sample.

Turning to Tables 9 and 10, the estimated relationships are generally similar for the industrial price equations as for the residential price equations. However, the retail competition effect, on the order of 5%, is numerically smaller at the means of the sample and is estimated less precisely than for the residential price equations.

These results are consistent with the view that PURPA was bad for consumers from a retail price perspective, but that wholesale competition, captured with the EWG variable, and retail competition have both been associated with lower retail prices once the major input cost drivers are controlled for. These results must be interpreted with care, however. There are several caveats. First, the price data are likely to be imperfect. Reported retail price data ultimately rely on reports filed with the Energy Information Administration (EIA). It is fairly clear that it took some time for EIA to take full and appropriate account of the impacts of retail competition on the price data reported to them. To the extent

Table 10. Industrial Price Equations 1981-2003 (standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.53	0.48	0.23
	(0.03)	(0.031)	(0.026)
HYDRO	-0.40	-0.29	-0.62
	(0.10)	(0.15)	(0.12)
NUCLEAR	0.11	0.056	0.029
	(0.071)	(0.075)	(0.057)
YIELD	0.078	0.079	0.029
	(0.0045)	(0.004)	(0.004)
SIZE	-0.4	-0.4	-0.3
	(0.04)	(0.04)	(0.03)
PURPA	0.24	0.10	0.18
	(0.09)	(0.09)	(0.072)
EWG	-0.24	-0.23	-0.15
	(0.054)	(0.055)	(0.042)
RETAIL	-0.18	-0.20	-0.043
	(0.039)	(0.039)	(0.03)
R^2 (corrected)	0.61	0.68	0.82

Source: See text and appendix

that customers served by competitive retailers were excluded from the reports filed with EIA, the price data overestimate the actual prices realized by those customers who switched. To the extent that utility reports include only the delivery charges for customers who have switched, average prices may be underestimated. Second, several of the right hand side variables are not exogenous (though they change slowly). We know, for example, that retail competition was introduced in states with the highest retail prices and, other things equal, this would lead to an underestimate of the effect of retail competition. The long time series and the use of state-specific fixed effects should help to mitigate these problems, but not necessarily fully. Thus, further analysis to develop a more complete structural framework and relying on better data would be desirable.

6. CONCLUSION

The transition to competitive electricity markets has been a difficult process in the United States. In 1997 I wrote "[E]lectricity restructuring ... is likely to involve both costs and benefits. If the restructuring is done right...the benefits ... can significantly outweigh the costs. But the jury is still out on whether policymakers have the will to implement the necessary reforms effectively" (Joskow (1997), p. 136). I believe that statement continues to be true today. Creating competitive wholesale markets that function well is a significant technical challenge and requires significant changes in industry structure and supporting institutional and regulatory governance arrangements. It requires a commitment by policymakers to do what is necessary to make it work. That commitment has been lacking in the U.S. The major barrier to a successful restructuring and competition program in the U.S. at the present time is political. Many of the technical problems associated with creating well functioning competitive electricity markets have been solved, often through bitter experience. While FERC has been a leader in promoting competitive markets, the Bush administration and the Congress have provided tepid support at best. Political compromises over restructuring, conflicts between federal and state regulations, the mixing of states with and without competition programs, the absence of a strong pro-competition policy and associated statutory authorities coming from the Congress and advanced by the President have all worked to make successful reforms extremely difficult.

Despite these difficulties, considerable progress has been made and many useful lessons have been learned. There is growing evidence that competition can lead to cost and price reductions if policymakers will support the regulatory and institutional changes needed to allow competitive market forces to work. However, the creation of competitive market forces has also encountered some significant and costly problems and it is important that future policies reflect the lessons learned from this experience. My interim assessment is that the glass is half full rather than half empty at the present time. I take this view based on the evidence of performance improvements and because the revisionist history about the "good old days of regulation" has conveniently ignored the $5000/Mw nuclear power plants, the 12 cent/kWh PURPA contracts, the wide variations across utilities in the construction costs and performance of their fossil plants, and the cross-subsidies buried in regulated tariffs that characterized the regulatory regimes in many states. As we look at the costs and benefits of competition we should not forget the many costly problems that arose under regulation.

Looking at the maps in Figure 1 and Figure 3 it seems clear that about half of the country is focused on moving forward with pro-competition policies, at least at the wholesale level, and half is not. Going forward I suspect that we will see a sort of contest between the performance of the regulated monopoly framework and the competitive market framework for governing the electric power sector in the U.S. With continuing analysis of comparative performance of alternative institutional arrangements we will be able to determine more definitively what is the best that we can do in an imperfect world.

DATA APPENDIX

State-level data from 1970 through 2003 were used to estimate the regression coefficients for equation (1) as reported in Tables 7, 8, 9 and 10. Maryland and the District of Columbia have been combined for all years due to the sources' combined data presentation in several years. Idaho was dropped due to data imperfections. Data construction becomes challenging after 1997 as a result of divestiture of utility plants, entry of EWGs and spread of retail competition. EIAa, EIAb, EIAc are used extensively to fill gaps in EEIa and EEIb.

Retail electricity prices: Retail prices are measured as average revenue per kWh sold to residential and industrial customers respectively for total electric power industry by state. These data include municipal and cooperative distribution companies. EEIa, EIAa, EIAb, EIA (2005).

Average fuel cost (adjusted for changes in CPI with 1970 = 1): Average real fuel cost per kWh of electricity generated in each state, including by independent power producers after 1997. EEIa, EIAa, and EIA (2005).

Hydro electric generation share: Fraction of total electricity generated in each state accounted for by hydroelectric generating capacity. EEIa and EIA (2005).

Nuclear generation share: Fraction of total electricity generated in each state accounted for by nuclear generating plants. EEIa and EIA (2005).

PURPA generation share: Estimate of fraction of total electricity generated in each state accounted for by PURPA Qualified Facilities. Series starts in 1986. MWh of PURPA generation assumed constant after 1997. EEIb and EIA (2005). Overlap years are averaged.

EWG generation share: Estimate of fraction of generation in each state accounted for by unregulated generators, excluding PURPA generators. Series starts in 1998. EIA (2005).

Real bond yields: Moody's average yield on electric utility bonds minus the annual rate of inflation in consumer prices (CPI).

Average residential and industrial kWh consumption per customer: Average consumption per retail customer for residential and industrial customers for the total electric power industry by state. EEIa, EIAa, EIAb, EIA (2005).

Retail competition: Dummy variable = 1 if retail competition. Author's assessments based on programs initiated in each state. First retail competition program 1998. California is treated as having retail competition beginning in 1998.

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New England Energy Alliance

October 2006

New England was one of the first regions of the country to restructure the industry that generates, transmits and delivers electricity. The key catalyst was the persistently high cost of electricity which put the region at a competitive disadvantage. By the late 1990s, all of the New England states except Vermont passed legislation to move toward competitive retail markets, and in 1999, the region's competitive wholesale electricity market was launched.

Many of the results have been positive, although issues concerning market effectiveness remain and continue to be debated. In this report, prepared by Polestar Communications & Strategic Analysis for several members of the New England Energy Alliance[1], you will see that the operating performance of power plants has improved significantly, emission rates from the generation of electricity have declined dramatically even as electricity generation has increased 25 percent, and consumers have cumulatively saved between \$6.5 to \$7.6 billion between 1998 and 2005 based on projections of where prices would have trended in the absence of restructuring. Those savings largely result from wholesale market performance and state mandated rate reductions, and do not reflect recent natural gas price volatility.

Unfortunately, electricity supplies are not keeping pace with demand growth, despite an initial burst of power plant construction in the early years of restructuring. In addition, the region has become heavily dependent on natural gas to fuel electricity generating plants. Yet, facilities needed to diversify and increase supplies of natural gas and electricity often face strong political and community opposition. This lack of infrastructure development jeopardizes the benefits from the competitive markets.

To address these infrastructure and diversity concerns – both of which are underlying factors in the region's high cost of energy – political leadership is needed to encourage investment and to make siting and permitting of energy facilities more predictable and timely. The New England states also need to work more closely to harmonize state policies and regulations.

This paper provides insights on the region's electricity industry restructuring efforts and offers principles for your consideration that are designed to help guide future policy development. We hope you find it useful.

Sincerely,

Carl Gustin
President

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[1] Constellation NewEnergy, Dominion Resources, Duke Energy Gas Transmission, Edison Electric Institute, Entergy Corporation, KeySpan Energy, National Grid, Nuclear Energy Institute, SUEZ Energy North America, TransCanada Corporation

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A Review of Electricity Industry Restructuring in New England

Prepared for Members of: The New England Energy Alliance

By:
Polestar Communications & Strategic Analysis
Boston, Massachusetts

September 2006

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Contents

I. Introduction and Summary

General

The New England states were among the first in the nation to restructure wholesale and retail electricity markets beginning in the late 1990s. In large part, the action was prompted by the burden of having the highest electricity costs in the country, which created hardships for residential consumers and handicapped many businesses from competing on a "level playing field" with companies located outside the region.[2]

Restructuring required most electric utilities to: sell their generating plants, allow consumers to choose among electricity suppliers and procure electricity for those consumers not choosing an electricity supplier – while remaining regulated and responsible for local distribution service. Wholesale restructuring involved creating a fair and reliable market for competition in generating electricity while ensuring equal access to transmission grids. Once established, the wholesale market caused electricity to become a commodity with prices set not by regulators, but by market rules and the balance between supply and demand.[3]

In has been seven years since the region's wholesale marketplace was launched and within this timeframe all the New England states – with the exception of Vermont – have introduced competition into retail markets. Sponsored by the New England Energy Alliance, this white paper presents what may well be the first integrated review of the progress of restructuring in New England. Formed in August 2005, the Alliance advocates for policies to ensure the availability, reliability, and affordability of energy supplies which are vital to the region's economic growth and prosperity.

The aim of this paper is three-fold: first, to identify and quantify the performance of the regional wholesale market; second, to review and qualitatively compare individual state retail markets; and third, to assess the impact of restructuring on generation and fuel source infrastructure. In short, this paper represents a static snapshot assessment of restructuring from its initiation through 2005 based on three public expectations that were widely discussed in the late 1990s: [4]

- ***creation of consumer economic savings*** – Are retail electricity price trends lower or higher today than they would have been in the absence of restructuring, both nominally and after adjusting for inflation? [5]

[2] A number of factors contributed to the high cost of electricity in the region including: the lack of indigenous fossil fuel resources making the region totally dependent on fossil fuel imports; the region's high cost of living which translates into higher prices for labor, housing, electricity, etc.; and expensive utility capital investments.
[3] The wholesale market is administered by ISO New England, which is overseen by the Federal Energy Regulatory Commission (FERC).
[4] This paper makes no judgment as to whether or not the formerly regulated electric utilities could have achieved the same performance level if restructuring had not taken place.
[5] It was beyond the scope of this paper to project the future sustainability of any economic savings from restructuring.

- ***consumer choice of suppliers*** – Do customers now have more options in terms of choice of electricity suppliers, products and services?

- ***enhancement of environmental benefits*** – Have emissions of sulfur dioxide, nitrogen oxides, and carbon dioxide from the generation of electricity decreased?

The most recent data and information available from state public utilities commissions and energy offices, the U.S. Energy Information Administration, as well as ISO New England are applied throughout the paper.[6] Wherever appropriate, simplified calculations are provided to show key trends and/or to summarize results.

The paper is divided into four additional sections plus an appendix. Section II addresses the regional wholesale market, which is overseen by ISO New England. In Section III, state retail markets are considered both individually and collectively with associated mandated programs reviewed in the Appendix. Section IV considers infrastructure issues, specifically relating to generating capacity and fuel supply diversity. Finally, Section V presents the principles adopted by the Alliance to guide the development of future regional energy policies.

Wholesale Market Performance

In evaluating changes since the competitive wholesale marketplace was launched, five indicators were considered: market participation; infrastructure investment; generating plant performance; wholesale price trends; and financial risk transfer. The environmental impacts of restructuring were also assessed.

- ***Market Participation:*** More than 280 companies either participate or are eligible to participate in the market comprised of $11.2 billion in annual electricity transactions.

- ***Infrastructure Investment:*** An unprecedented 10,000 MW of new generation was added during the first six years of restructuring – increasing supply by ~30%. Since then, further investment has stalled because of both real and perceived financial risks associated with the recovery of capital and the "boom or bust cycle" of infrastructure that requires long lead times to permit and build. As a result, current generation resources may not be sufficient to maintain electricity grid reliability as early as 2008.

  Transmission capacity is also insufficient and is causing bottlenecks that are costing consumers hundreds of millions of dollars in congestion costs. Since 2001, however, 75 projects have been placed in service with five major additional projects underway totaling more than $1.5 billion that will alleviate bottlenecks, some of which have been in existence

[6] Generally, this data and information is complete through 2005, but there are exceptions and they are noted within the text. These exceptions include natural gas consumption data which is reported by EIA through 2004 and customer migration data which reflects the most recent data available from each state's Public Utility Commission (which vary between year-end 2005 and mid-2006) . It should also be noted that there are significant reporting inconsistencies among the states which limits the analysis. Consumer migration, energy efficiency, and renewable program results, for example, are tracked differently in each state.

for up to 20 years. Despite this effort, $1 billion in additional upgrades to the transmission system are still required.

- ***Generation Performance:*** The combination of competition, new plant ownership, and reduced operation of inefficient plants has improved generating plant performance. Since wholesale restructuring, plant availability has increased by 8%, avoiding the construction of up to five, 400 Megawatt generating facilities.

- ***Wholesale Prices:*** According to ISO New England, competitive forces have led to a reduction in wholesale electricity costs of approximately $700 million annually. However, this savings is tempered with a 47% increase in wholesale costs during 2005 due to the unprecedented high price of natural gas. After adjusting for fuel costs (which are beyond the control of regional markets), wholesale electricity spot-market prices were between 2 to almost 6% lower between 2003 through 2005 than in 2000.

- ***Financial Risk Minimization:*** Generating companies, not utility ratepayers, now assume significant financial risk with respect to infrastructure investment. A clear sign of this risk transfer is that some companies that overpaid for generating plants in the region (when utilities were required to divest their assets) have transferred those assets to lenders or even declared bankruptcy.

  Because plants are no longer allowed a regulated rate of return, some are experiencing financial difficulties because of an inability to fully recover fixed costs under the wholesale market operating structure. Many of these plants continue to operate to maintain reliability standards under FERC-approved arrangements called "Reliability Must Run" (RMR) agreements which cost consumers about $700 million annually. An upcoming change to the wholesale market is intended to correct this dislocation with the development of a "Forward Capacity Market" (FCM) to compensate generators for fixed costs and encourage investment in new power plants – estimated to cost consumers about $5 billion through 2010.[7] While it remains to be seen how many new power plants will actually be built, initial reaction to the FCM from generating companies has been positive.[8] But new plants will still have to overcome regulatory, permitting and financing hurdles.

- ***Environmental Protection:*** Three traits of restructuring including construction of new generating capacity, better generating plant performance and increased generating plant efficiencies – combined with some of the most stringent environmental regulations in the country – have resulted in significant reductions in emissions. While electricity generation within the region increased 25% between 1998 and 2004, associated sulfur dioxide (SO_2) emission rates decreased by 56%, nitrogen oxide (NO_x) by 57% and carbon dioxide (CO_2) by 22%.

[7] ISO New England estimates that Forward Capacity Markets will provide about $5 billion in transitional revenues to generators until the market is fully implemented in 2010 (with payments beginning in December of 2006). The first forward capacity auction is scheduled to take place during the first quarter of 2008, to cover capacity needs for June 2010 through May 2011.

[8] "Flurry of Power Plant Proposals Offers Hope", *The Boston Globe,* September 25, 2006.

State Retail Markets

Five of the six New England states restructured their electricity industries – all with varying approaches and timeframes. The status of restructuring in each state, along with an estimation of consumer economic benefits and the progress of retail competition is provided below. Included in the Appendix is a review of state mandated energy efficiency and renewable programs.

It should be noted that neither of the two primary goals of state restructuring – consumer savings and choice – were explicitly defined by any of the state legislatures. To this day, they still mean different things to different people and are, therefore, not surprisingly, the nexus of ongoing debate about the success of restructuring.

- ***Retail price assessment:*** Through state administered rate reductions, utility supply procurement requirements, and competitive wholesale market forces, all electricity consumers have benefited economically from restructuring. Based on a comparison of actual retail electricity prices against a projection of where they would likely have trended in the absence of restructuring from 1998 to 2005, New England consumers have cumulatively saved between \$6.5 and \$7.6 billion.[9] On a state-by-state basis, savings range from \$3.4 billion in Massachusetts, to essentially "break-even" in Maine.

  After adjusting for inflation, all the New England states (including Vermont which has benefited from wholesale market efficiencies) have lower retail electricity prices – 7 to 18% through 2005 when compared to those years just prior to restructuring. However, more recently, record-high natural gas prices, environmental compliance costs, and transmission congestion costs are reducing these economic benefits.

- ***Customer Choice:*** While consumer switching from utilities to competitive suppliers has progressed fairly well among medium and large manufacturers and businesses in some states, the level of competition remains very limited in the smaller commercial and residential sectors throughout the region. Massachusetts and Maine have had the most success building a market for competitive service providers. In those states, competitive suppliers now serve more than a third of total retail load and about 80% of the large industrial load. Approximately 10% of Rhode Island's electricity load is currently served by competitive suppliers. The number of consumers served by competitive suppliers in both Connecticut and New Hampshire remains low, although there are indications that migration to competitive suppliers is beginning to occur as standard offer transition periods have either recently expired or soon will, and large manufacturers and businesses are or will soon be experiencing changing utility pricing.

  Key reasons for the lack of greater retail competition in some customer segments include: the lack of or minimal price difference between utility offered and competitive supplier service; the high cost to suppliers to acquire smaller customers; and limited consumer

[9] First order calculations were performed to quantify this range of savings. The high end value reflects a comparison of the actual weighted average regional retail rates against a projection of where rates were trending had a regulated industry structured continued (from 1998 to 2005). The lower value was quantified based on the same methodology applied to each individual state. See page 23 for a more detailed description of these calculations.

knowledge about restructuring particularly in the residential and small commercial customer sectors.

- ***Energy Efficiency:*** New England ratepayers contribute about $240 million each year to fund energy efficiency programs implemented in each state. These programs save the region enough electricity annually to meet the needs of about 125,000 homes and reduce peak demand by about 140 Megawatts per year.[10] Between 2000 and 2004, efficiency programs avoided the generation of more than: 30,000 tons of SO_2; 9,000 tons of NOx; and 8 million tons of CO_2.

- ***Renewable Programs*:** Massachusetts, Connecticut and Rhode Island mandated ratepayer funding for renewable project development. In addition, all of the region's states except New Hampshire have adopted renewable portfolio standards (RPS) – requiring that a percentage of electricity supply be provided by renewable generation sources. It has been estimated that an additional 1,000 Megawatts of new renewable generation in the region may be needed by 2010 to meet RPS requirements.[11] To date, however, fewer than 100 Megawatts of generation have been added – so achieving the legislated goal is in doubt. Moreover, if the goal is not met, hundreds of millions of dollars in compliance payments will be passed on to consumers with no electricity in return.

Infrastructure in Restructured Markets

The future performance of the region's restructured electricity market is dependent on the availability of adequate infrastructure. However, construction of new generating facilities is not keeping pace with increasing electricity demand which could impact the region's economic growth. In addition, the region has become heavily dependent on natural gas to fuel electricity generating plants:

- ***Generation Capacity Development:*** The region needs new generating capacity. It appears that the pending imbalance between supply and demand in the region has been caused by insufficient economic incentives for investment in new capacity. The recently FERC-accepted "forward capacity market" is intended to remedy this problem and provide incentives for meeting the region's future capacity needs.[12] While initial response from generators has been positive, the details have yet to be worked out and the impacts on the region's electricity market and economy remain uncertain. Contributing to this challenge are state environmental policies, namely the Regional Greenhouse Gas Initiative "RGGI", that have created uncertainty in terms of impacts on electricity prices and investment decisions. [13]

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[10] Estimate does not include reductions from demand reduction programs administered by ISO New England.

[11] "Electric Energy Efficiency and Renewable Energy in New England: As Assessment of Existing Policies and Prospects for the Future", The Regulatory Assistance Project, May 2005.

[12] The alternative to LICAP or Locational Installed Capacity Market.

[13] Seven northeastern states signed a memorandum of understanding in December 2005 to establish the first carbon dioxide cap and trade program in the U.S. RGGI includes all the New England states except Massachusetts and Rhode Island. Massachusetts has adopted a separate greenhouse gas reduction program.

- ➢ ***Fuel/Resource Diversity:*** The region's natural gas consumption has grown by 70% over the last decade – primarily for electricity generation. The balance between the supply and demand of natural gas in the region is tenuous and the consequences costly. Additional supplies of natural gas are needed, combined with more diverse sources of fuels for electricity generation including coal, nuclear, renewables as well as efficiency measures to ensure a reliable supply of electricity at an affordable price.

Political leadership is needed to overcome these challenges to guide: 1) the design, implementation and monitoring of proposed wholesale market changes to ensure that imperfections are corrected so that infrastructure is built when and where it is needed most; and 2) action to harmonize state policies, programs and regulations throughout the region to encourage infrastructure investment, facilitation of infrastructure siting and resource diversity.

While the report makes no explicit recommendations, the Alliance advocates the adoption of its principles (contained in Section V) to help guide policies and actions to ensure that the region has reliable and affordable supplies of electricity and natural gas. These principals provide a roadmap to the region's political leaders in reaching a consensus and implementing programs and initiatives to overcome the clear challenges outlined above.

II. Wholesale Markets

In less than a decade, the electric industry has been transformed from one dominated by vertically integrated monopolies that generated, transmitted and delivered electricity to one driven by competition with new participants, rules, procedures, systems and entities. This section provides an overview of the changes that have transpired and the performance of the wholesale marketplace.

General

Congress initiated the groundwork for deregulating wholesale electricity markets through provisions contained in the Public Utility Regulatory Policies Act of 1978 (PURPA). The Act mandated that regulated electric utilities provide a market for the output of non-utility generating (or power) plants that meet certain size, technology and environmental criteria.

Many state regulators required utilities to sign long-term purchase power contracts with small independent PURPA generators at the utilities' then avoided costs.[14] Plants built pursuant to PURPA represented the beginning of a new class of generators called independent power producers ("IPP's"). Further, pursuant to state-mandated integrated resource planning processes, regulators required utilities to compare the cost of utility-built generation with that of power from IPP's and to take the least cost alternative. This regulatory paradigm resulted in the maturation of the IPP industry across the country.

Thereafter, the move to competition in wholesale markets was advanced with the passage of the Energy Policy Act of 1992. The Act began the process of allowing open access to the existing transmission system to non-utility generators. Associated regulations issued by FERC (Orders 888 and 889) authorized open and equal access to all utilities' transmission lines for all electricity producers, thus facilitating wholesale and retail restructuring.

A cornerstone of the state-level restructuring that followed in most New England states was utility divestiture of generation assets. In the early stages of restructuring, most of the region's electric utilities sold their plants to merchant generating companies and power marketers.[15]

ISO New England, an independent system operator (ISO) approved by the Federal Energy Regulatory Commission (FERC), was formed to develop and administer a competitive wholesale market to ensure fair and open access to the region's transmission systems and unbiased

[14]PURPA was a legislative response to the oil embargoes of the 1970s and was an effort to wean the United States off of its reliance on imported oil. Long-term PURPA contracts along with expensive capital investments contributed to New England's high electric rates (among other factors) prior to restructuring. Today, consumers continue to pay the price in utility transition costs – a customer charge that covers utility contractual obligations that were approved by regulators prior to restructuring that would have been recovered at fixed rates over time under the old regulatory system. Transition costs are steadily declining as utility obligations are paid off.

[15] Utilities in Massachusetts, Connecticut, Maine and Rhode Island sold generation to competitive suppliers because they were either mandated to, or voluntarily agreed to divest generation sources in order to recoup stranded costs. Public Service Company of New Hampshire was required to sell its share of the Seabrook Nuclear Power Station, but was not required to divest its fossil/hydro generation assets.

administration of the markets. In May 1999, New England's wholesale electricity markets were formally launched and included new market arrangements, procedures, rules, systems and products to support the implementation of competition.[16]

When the wholesale market in New England was launched, ongoing refinements to the governing rules and systems should have been expected because the introduction of competition in the electricity generation industry did not closely parallel the experience of other deregulated industries. Since wholesale market initiation, ISO New England, with FERC approval, has made two significant design changes to marketplace rules and procedures.

Standard Market Design (SMD). On March 1, 2003, ISO New England implemented SMD – a major design overhaul of the wholesale electricity market.[17] The objective was to establish a common framework with neighboring regions to promote greater economic efficiency and inter-regional trade in order to further FERC's goal of standardizing wholesale markets nationwide. It was also adopted to increase the region's electricity reliability by providing clear economic signals indicating where supply and load are imbalanced and generation or transmission is needed most. New England's SMD was based on features of a wholesale electricity market design model adopted by the PJM Interconnection.[18]

A key component of SMD was the establishment of "locational marginal pricing" – an approach that divided the New England region into eight zones.[19] Locational marginal pricing recognizes that the region's transmission system can become congested during times of peak demand making it more expensive to deliver electricity to some specific geographic areas. Previously, such expenses were distributed among all consumers in the region. Now, these prices reflect the true cost of delivering and supplying electricity at every location on the grid, which is designed to provide incentive for the construction of new transmission infrastructure and generating facilities into those areas where they are most needed.

Congestion costs translate into higher electricity prices in import-constrained zones. ISO New England has estimated New England's transmission congestion costs to range from $50 million to $300 million per year. In 2005, wholesale electricity prices in Connecticut were approximately 17% higher on average than those in Maine – the regional zone with the lowest average energy prices.[20] Consumers in the Boston area and Southwest Connecticut (the two

[16] In the 1990s, as states and regions established wholesale competition for electricity, groups of utilities and their federal and state regulators began forming independent, transmission operators to ensure equal access to the power grid for new, non-utility competitors. Today, there are seven Independent System Operators and Regional Transmission Organizations (ISO/RTO) in the U.S.

[17] SMD was the third order in a series of FERC initiatives to increase the efficiency of competitive wholesale electricity markets. The intent of SMD was to increase open access to interstate transmission systems to allow market participants to compete on a level playing field with consistent rules for all players in all regions. FERC's proposed SMD rule issued in 2002, created considerable opposition in certain parts of the country and was withdrawn in July 2005. However, New England moved forward with competitive market development.

[18] The ISO region that formerly comprised Pennsylvania, New Jersey and Maryland.

[19] Connecticut, Maine, New Hampshire, Rhode Island, Vermont, Western and Central Massachusetts, Northeastern Massachusetts and Boston, Southeastern Massachusetts and Cape Cod.

[20] In 2005, the average day-ahead Locational Marginal Price difference between Maine and Connecticut was $12.33/Mwh or about 17% (or $70.82 versus $83.15 per MWh) from "2005 Annual Markets Report", ISO New England, June 1, 2006.

most congested areas in the region) are paying 10 to 20% more per year for electricity until additional transmission infrastructure is constructed or new generating plants are built closer to where electricity is most consumed.

An independent assessment of the region's wholesale market found that SMD in its first full year of operation operated as designed. SMD markets improved the efficiency of congestion management in terms of dispatching generation to satisfy energy demand and operating reserve requirements while maintaining power flows on the network.[21]

Regional Transmission Organization (RTO). In early 2005, FERC designated ISO New England as the regional transmission organization for the six-state region.[22] As an RTO, ISO New England's role has been expanded to include greater operational control of the region's transmission facilities, in addition to the administration and oversight of the region's competitive wholesale markets. FERC encouraged the formation of a northeastern RTO, covering New England, New York, and the Mid-Atlantic States, in order to achieve greater market efficiencies, but this concept did not come to fruition.[23]

ISO as an RTO exercises operational control over the region's transmission facilities pursuant to contractual arrangement with New England's transmission owners. Under this arrangement, ISO has clear authority to conduct regional planning and to identify the need for transmission upgrades. Transmission owners have agreed to build or arrange to have built the upgrades that ISO finds are needed. In return, the transmission owners receive FERC-approved incentives to participate in the RTO.

The designation of ISO New England as an RTO has the potential for significant qualitative benefits for consumers – such as increased reliability from better transmission planning and upgrading – but are difficult to quantify as they are intangible and some may not be realized in the short-term. The goal of an RTO is to ultimately lower costs to ratepayers through reduced transmission congestion (decreasing transmission costs and increasing access to lower cost generation) and by increasing electricity reliability.

Wholesale Market Performance

The New England power supply system is operated as a single control area with over 350 power plants, 8,000 miles of high-voltage transmission lines and 12 interconnections to neighboring systems serving 6.5 million businesses and households.[24]

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[21] "2004 Assessment of the Electricity Markets in New England", Potomac Economics, Ltd., June 2005.

[22] FERC is promoting the voluntary formation of RTOs to promote efficiency in wholesale electricity markets and the lowest price possible for reliable service. FERC Order No. 2000 amended its regulations under the Federal Power Act to advance the formation of RTOs requiring each public utility that owns, operates or controls facilities for the transmission of electric energy in interstate commerce to make certain filings to form an RTO.

[23] As of mid-2005, over 50% of the generating capacity in the U.S. is operating within an ISO/RTO context. RTOs include the Midwest Independent Transmission System Operator; PJM Interconnection; ISO New England, and the California ISO. Additionally the New York ISO provides RTO elements, but is an ISO rather than an RTO, and the Electric Reliability Council of Texas provides many RTO functions, but is not FERC jurisdictional.

[24] "2005 Annual Markets Report", ISO New England, June 1, 2006.

As a commodity, electricity is sold through fixed contracts between wholesale buyers and sellers and through short-term (day-ahead) or spot (real-time) trading. About 75% of electricity trading activity is done through bilateral transactions – contracts to purchase or sell electricity over specified time periods under set prices. Bilateral transactions provide price certainty because these arranged contracts are fixed and not subject to external market forces Spot- (real-time) and short-term (day-ahead) trading is typically relied upon as a "balancer" between supply and demand.

Five parameters were selected to serve as marketplace performance indicators: market participation; infrastructure (generation, transmission) investment; generating plant performance; wholesale price trends; and financial risk transfer.

Market Participation. More than 280 companies and entities either participate or are eligible to do so in New England's wholesale marketplace and complete $11.2 billion of electricity transactions annually.[25] Participants include power generators, transmission owners, electricity suppliers (marketers and brokers), publicly owned municipal utilities and large end-users. Since the markets opened in 1999, there has been a 71% increase in the number of eligible wholesale market participants, with actual participation varying by state.[26] Before retail restructuring was initiated, for example, there were approximately 15 electric utilities in New England (excluding municipal utilities) that operated all the region's generating plants. There are now more than 35 companies operating generating plants with the largest owning no more than about 15% of the region's supply.[27] An independent assessment commissioned by ISO New England on the performance of the region's wholesale electricity market for the calendar year 2004 found it to be "fair and competitive".[28]

Generation Capacity Investment. Electricity consumption has increased by 15% in the region since the competitive wholesale marketplace was established.[29] Investors responded by investing more than $9 billion to build some 25 new generating plants in just a 6-year timeframe, increasing the region's electricity supply by 30%. In an absolute sense, there is no precedent prior to restructuring for the quantity of generating plants built and brought to commercial operation over such a short period of time.

However, in recent years, investment in new generating facilities has slowed considerably. ISO New England estimates that only about 1,000 MW of new capacity will be added in the next several years – which is less than half of expected demand growth. To complicate matters, a portion of the region's older electric and gas infrastructure may need to be replaced or undergo substantial refurbishment to remain in operation. As a result, according to ISO New England, current generation resources may be insufficient to maintain the reliability of the electric grid in some parts of New England during peak demand periods as soon as 2008. There are several aspects to this infrastructure issue – which are discussed in Section IV.

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[25] "2005 Annual Markets Report", ISO New England, June 1, 2006.
[26] "ISO New England: Delivering Value to the Region", 2005.
[27] According to data contained in ISO New England CELT Report.
[28] "2004 Annual Markets Report", ISO New England, July 2005.
[29] Statistics from Energy Information Administration, U.S. Department of Energy.

Transmission Infrastructure Investment. In the competitive marketplace, the dispatch of electricity over the region's 8,000 miles of transmission lines generated by more than 350 power plants is challenging because New England's electricity system was built by individual utility companies, each serving local load and each coordinating their generation and transmission construction and operations. Moreover, a significant portion of the transmission system is more than 30 years old and has become too small to handle the volume of electricity now demanded. In the decade prior to the formation of an RTO, transmission infrastructure capital investment was lagging, which consequently puts the region in a catch-up mode today.

A recent industry study confirmed that transmission investment has not kept up with either demand growth or generation investment and has not been sufficient to accommodate the advent of regional power markets.[30] It is important to note that the region would likely have had a transmission infrastructure capacity shortfall even if the former regulated utility structure remained in place. The broad flow of electricity in a competitive marketplace has simply exacerbated this situation along with transmission siting difficulties historically prevalent throughout the region.

Improvements, however, are being made. Since 2001, seventy-five projects have been placed in service totaling $217 million in construction costs and many others are well on their way to completion.[31] For example, five major bulk transmission system projects totaling more than $1.5 billion in four states have been initiated which should ultimately reduce congestion costs and improve the flow of electricity within the region.

NSTAR is nearing completion of a $60 million transmission line in greater Boston, bringing 25% more electricity into the City which should moderate prices in this zone.[32] The Northeast Utilities/United Illuminating Company 345 kV project will improve the transfer of power and system performance in Southwest Connecticut. Phase I of the project is under construction with a projected in-service date of December 2006 which will increase the area's import capability by 275 Megawatts. Phase 2, currently in the final design stage, will increase the import capability by 825Megawatts. It is scheduled for completion in December 2009.[33] Other large-scale transmission projects underway include a Northeast Reliability Interconnect Project that will improve transfer capability between New England and New Brunswick, and the Northwest Vermont Reliability Project that will improve the transmission system in that area.

However, more system upgrades are needed. In addition to the large-scale projects listed above, ISO New England's 2005 Regional System Plan identifies over 200 additional transmission infrastructure projects estimated to cost approximately $1 billion that will be needed to ensure a reliable supply of electricity over the next ten years.[34]

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[30] "Transmission: The Critical Link," National Grid, 2005.
[31] "2005 Regional System Plan", ISO New England, October 20, 2005.
[32] The NSTAR 345 kV Reliability Project consists of three cable circuits. The projected in-service date for the first two cable circuits is December 2006 which will increase import capability by 900MW. The third cable is scheduled for service before the summer of 2008 and will increase import capability by another 200MW.
[33] "2005 Regional System Plan", ISO New England, October 20, 2005.
[34] "ISO New England's Annual Assessment Targets Continued Power System Enhancements", ISO New England, October 20, 2005.

Generation Performance. The combination of competition and new ownership (through the divestiture of assets mandated or encouraged by retail restructuring at the state level) created incentives for the incremental improvement of generating plant performance. Since the establishment of competitive wholesale markets, overall "generator availability" has increased by more than 8%.[35] The electricity produced from increased plant efficiencies has avoided the construction of up to five, 400 Megawatt generating facilities. Moreover, increased generating plant efficiency and availability reduce wholesale market costs – savings, which may be passed on to retail consumers – and decrease emissions to the environment, depending on fuel type.

Table 1 contains the annual weighted availability factors of the New England generating units from 1995 to 2005. As shown in the shaded area, the system average generator availability has increased to about 88% since the initiation of competitive wholesale markets.[36]

Some of the availability improvements cited in Table 1 are because older, inefficient plants were retired and the operation of others converted to a peaking mode, which generally results in a higher availability factor. On the other hand, the region's nuclear plants have unmistakably experienced significantly improved availability factors under new ownership which drives the regional average upward. Interestingly, the older natural gas combined-cycle generating plants have improved, but the new facilities appear to be underperforming – which may be due to "working the bugs out" during start-up.[37]

Table 1 shows that under a competitive wholesale market, existing generating plants operate more efficiently, consuming less fuel per unit of electricity produced. The weighted average heat rate for oil-fired generating facilities, which is a measure of the amount of oil required to produce a specified amount of electricity, has improved by 5.6% since 2000.[38] Similar efficiencies in the region's coal-fired and nuclear plants have been realized as well. In the case of oil-fueled plants, this favorable decline could be due to the retirement or less frequent operation of older facilities.

[35] "2004 Annual Markets Report," ISO New England, July 2005.

[36] According to ISO New England, the decrease from 1996 through 1998 can be attributed to the outage of nuclear units during this period.

[37] "Annual Markets Report, May – December 2002", ISO New England, August 13, 2003. According to ISO New England, when these generators are first placed into commercial service, they typically perform below design criteria. However, after break-in and with design modifications, their availability approaches the technology's target levels.

[38] "2004 Annual Markets Report", ISO New England, July 2005.

Table 1
New England Generating Plant Average Availability Factors (%)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
System Average	**79**	**78**	**75**	**78**	**81**	**81**	**87**	**89**	**88**	**88**	**88**
Fossil Steam	81	81	84	81	79	78	83	85	87	86	86
Nuclear	63	53	32	53	82	89	92	91	91	94	89
Jet Engine	88	92	94	93	70	88	95	94	94	97	95
Combustion Turbine	94	92	96	92	90	83	89	92	93	97	95
Combined Cycle:	90	92	92	89	83	80	85	90	85	86	86
- Pre-1999	90	92	92	89	91	89	96	92	91	92	92
- 1999-2004	n/a	n/a	n/a	n/a	47	67	76	89	84	84	86
Hydro	83	88	86	86	81	81	96	96	95	94	94
Pumped Storage	97	94	97	91	86	86	95	87	92	90	92
Diesel	90	94	90	89	88	88	98	98	98	95	98
Source: "2005 Annual Markets Report", ISO New England, Inc.											

Wholesale Prices. New England wholesale electricity prices have decreased since 2000 after adjusting for fuel costs (which significantly fluctuate under international, weather and production influences that are beyond the control of regional markets). According to ISO New England, competitive market incentives to improve generator availability, enhance operation and make infrastructure more efficient, along with new generating facilities, reduced wholesale electricity prices by 5.7% through 2004, leading to an annual cost reduction of $700 million. The amount of the reduction realized by retail consumers may differ.

Table 2 provides a summary of actual real-time (or spot market) electricity prices for the period 2000 through 2005 as well as those normalized to year 2000 fuel price levels. With the fuel cost adjustment, the 2005 average wholesale electricity price was still lower than it was in 2000, which reflects the increase in generating plant availability and other competitive factors.

In terms of actual wholesale prices, the substantially higher electricity price during 2005 was driven by the unprecedented high cost of natural gas. During that year, units burning gas or oil set wholesale electricity spot prices 87% of the time and the price of natural gas increased by 47% -- which, in turn increased the wholesale price of electricity by that same amount.[39] During high price periods, natural gas packs a double economic punch to New England because when the price of this fuel increases, so does electricity.

[39] "2005 Annual Markets Report", ISO New England, June 1, 2006.

Table 2
Actual and Fuel-Adjusted New England Real-Time (Spot Market) Electricity Prices

	2000	2001	2002	2003	2004	2005
Actual electric energy price ($/MWhr)	$45.95	$43.03	$37.52	$53.40	$54.44	$79.96
Electric energy price normalized to year 2000 fuel-price levels ($/MWhr)	$45.95	$48.60	$46.65	$43.51	$43.33	$44.99
Source: "2005 Annual Markets Report", ISO New England, June 1, 2006						

As a cross-check on how well the region is faring under competitive wholesale markets, Table 3 provides a snap-shot comparison of the average 2004 and 2005 electricity price across adjoining ISO's. As shown, New England is in the middle with little chance of matching PJM's price which relies on low-cost nuclear and coal-fired generation to meet more than 90% of its electricity.[40]

Table 3
Adjoining ISO Average "Real-Time" Electric Energy Prices

ISO Area	2004 ($/MWhr)	2005 ($/MWhr)
New England	$51.53	$76.66
New York	$55.73	$84.36
PJM	$43.78	$58.11
Sources: "2004 and 2005 Annual Markets Report", ISO New England.		

Financial Risk Minimization. Prior to restructuring, electricity was dispatched on a regional basis according to an economic-based calculation that ranked each generator's marginal operating cost from the least to the most expensive. Regulated utilities were allowed to recover generating facility fixed costs, subject to prudency reviews by regulators.

Under the competitive wholesale model, generating companies offer electricity at market-based prices and accept the financial risk in doing so. The results have been mixed. Some generating companies have done well financially. Other companies that invested in generating plants in the region have experienced financial difficulties and have transferred generating assets to their lenders or declared bankruptcy. Clearly, in some instances, companies may have overpaid for the assets that they purchased from the regulated utilities under mandated divestiture requirements. In other instances, these situations are occurring because some plants have been unable to recover fixed costs as wholesale market revenues have not been sufficient.

Instead of shutting down (which generators cannot do unless ISO New England permits them to do so), many if not all of these plants continue to operate under fixed-cost reliability agreements

[40] PJM's 2005 fuel mix was reported to be 57% coal, 34% nuclear, 5% natural gas and 2% oil-fired and 2% renewables. Reference: PJM Environmental Information Services, GATS Subscriber Group Meeting, February 17, 2006.

called Reliability Must Run Agreements (RMRs). Subject to FERC approval, these agreements provide financial support to ensure that units needed for reliability continue to be available. The need for these agreements suggests that the current market structure does not adequately compensate generators providing reliability service (that is, only operating periodically when electricity demand is peaking).[41]

As of December 31, 2005, RMRs were in effect for 14 generating stations, comprising 4,719 Megawatts of capacity, or 15% of the total system-wide capacity. In Connecticut, approximately half of the generating capacity is operating under some form of reliability agreement costing consumers approximately $330 million annually. Massachusetts has seven generating plants totaling about 1500 Megawatts operating under reliability agreements, costing consumers $375 million annually.

The high number of RMRs demonstrates the need for wholesale market changes (i.e., pending Forward Capacity Market implementation) to allow generators to recover fixed costs and encourage new infrastructure investment.

Environmental Emission Reductions

A key driver in restructuring efforts was environmental protection – namely the reduction in atmospheric emissions from the generation of electricity. The environmental benefits from restructuring have been leveraged by federal (The Clean Air Act and its Amendments) and state air quality regulations that were promulgated coincident to the individual state efforts. For example, Massachusetts was the first state in the nation to limit carbon dioxide (CO_2) and mercury emissions from electricity generating plants.[42]

These environmental regulations led to significant investment in emission control equipment – in some cases hundreds of millions of dollars per plant – by the new owners of generating facilities after their divestiture by the formerly regulated utilities. More importantly, the more rigorous air emission regulations coupled with siting requirements made the construction of new natural gas-fired generating plants the investment of choice by developers (which as subsequently discussed in Section IV has led to heavy dependence on this fossil fuel).

Over the past six years, there have been very significant air quality improvements even though electricity generation within the region increased almost 25% during the same timeframe. Put simply, electricity production has risen and emissions have declined.

Emission Trends. Two traits of wholesale market restructuring, construction of new generating capacity and increased generating plant performance, were considered in assessing

[41] An upcoming change to the wholesale market involves the development of a "Forward Capacity Market" which will increase compensation to all generators.

[42] In 2001, Massachusetts enacted strict regulations applicable to the state's oldest power plants requiring significant reductions in SO_2, NOx, and even CO_2 (currently federally unregulated) which required major upgrades of pollution control technology or re-powering of facilities. Compliance deadlines were phased-in over a seven-year period. In 2004, Massachusetts also adopted regulations to cut mercury emissions from coal-fired facilities – and previously promulgated regulations for the mitigation of mercury emissions from trash-to-energy facilities.

emission trends (the environmental benefits of ongoing electricity efficiency programs are a function of state mandated programs and are summarized in the Appendix). It was beyond the scope of this paper to assess the effects of the new federal and state environmental regulations on the emission reduction trends which undoubtedly also played a key role.

- ***Natural gas-fired generation:*** Since restructuring, generation capacity in New England increased by 11,000 Megawatts, almost all of which was natural gas-fired. Natural gas-fired combined-cycle plants offer extremely high efficiency – up to double that of other fossil-fueled generating facilities emitting almost 5 times less nitrogen oxide, up to 55% less carbon dioxide and no sulfur dioxide, compared to either oil or coal.

  Investment in this new generation has resulted in either the retirement or the reduced operation of some older plants with higher emission rates and has enabled new electricity demand to be met with fewer emissions. More specifically, restructuring has led to several fossil-fired generating plants to be: retired (and replaced with new natural gas fired facilities); refurbished or retrofitted with emission controls that go beyond federal and/or state requirements.

- ***Increased operating efficiency:*** As discussed previously, generating plant efficiencies have increased in the competitive marketplace (due to better performance or the predominant operation by the most efficient facilities) which means that less fuel is consumed per unit of electricity produced which in turn means fewer emissions. In addition, the availability factor of emissions-free nuclear generating plants has improved substantially which presumably defers the operation of fossil-fired units thereby reducing emissions.

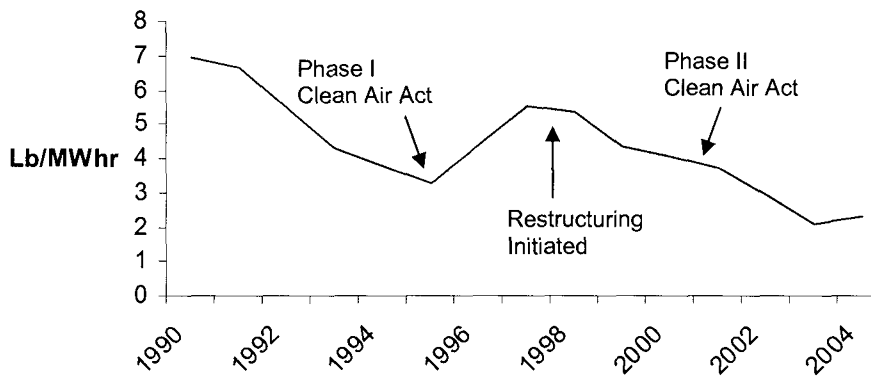
Figures 1 through 3 show emission trends from electricity generation in New England for: sulfur dioxide (SO_2), which is responsible for acid rain; nitrogen oxide (NO_x), which produces smog; and carbon dioxide (CO_2), a key driver in global warming.

Between 1998 (as restructuring was initiated in three of the six New England states) and 2004, the emission rates from generating electricity have declined by: 56% for SO_2, 57% for NO_x and 22% for CO_2.[43] As noted above, this decline was not entirely due to restructuring.

In Figures 1 and 2, the impacts of the Clean Air Act and its amendments can be seen between 1990 and 1999 (just as restructuring was initiated) as SO_2 and NO_x emissions rates declined due to generating plant technology and equipment retrofits.

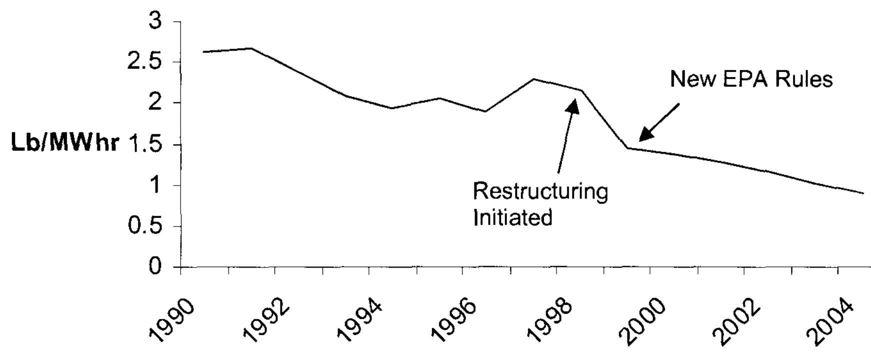
[43] Based on weighted average of state electricity generation and emissions data, Energy Information Administration, U.S. Department of Energy.

Figure 1 – New England Generating Plant SO_2 Emission Trend



Source: Energy Information Administration, U.S. Department of Energy

Figure 2 – New England Generating Plant NO_x Emission Trend



Source: Energy Information Administration, U.S. Department of Energy

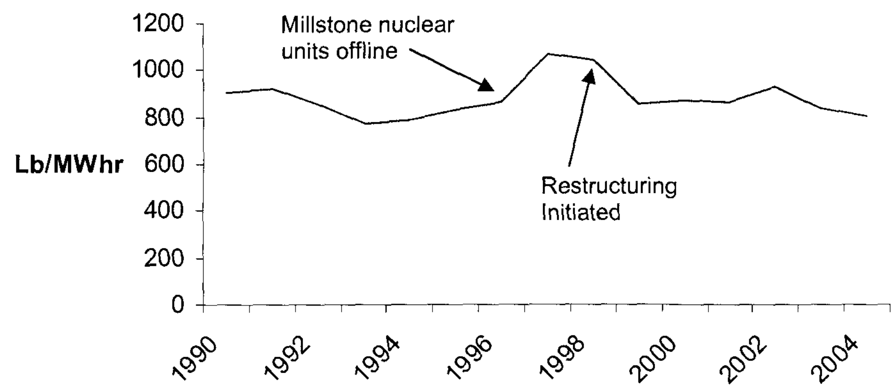
Between 2000 and 2003, electricity generation increased by 15% and emission rates dropped sharply – primarily from the construction of new natural gas-fired plants that was spurred by restructuring and strict environmental compliance of existing plants. It should be noted that the visible increase in emissions in the late 1990's were due to increased emissions from fossil fuel generation used as replacement power for the Millstone nuclear units which were shut down for an extended outage (and potentially for replacement power for two other smaller nuclear plants that were permanently shut-down, Maine Yankee and Connecticut Yankee). The output of the emission-free nuclear units was replaced by generation from fossil-fired plants.

In later years, the improved operation of the region's nuclear plants is also a factor in reducing the emissions of SO_2, NO_x and CO_2. The performance of these plants on average improved by

20% from 1990 through 2005 – a trend that continued under restructuring when nuclear units were purchased by companies specializing in nuclear plant operations.

As shown in Figure 3, the emissions of CO_2 have declined slightly but notably – marking the first time there has been a roll back in greenhouse gas emissions in the region – an important accomplishment given that four of the six New England states signed a memorandum of understanding establishing the first carbon dioxide cap and trade program in the U.S. The Regional Greenhouse Gas Initiative (RGGI) includes all of the region's states except Massachusetts and Rhode Island and is intended to maintain current CO_2 emissions levels from electricity generation through 2015, and then reduce them 10% by 2019.[44]

Figure 3 – New England Generating Plant CO_2 Emission Trend



Source: Energy Information Administration, U.S. Department of Energy

[44] Massachusetts and Rhode Island did not sign the RGGI agreement. Massachusetts has a greenhouse gas emission reduction program already in place; and while New Hampshire signed the agreement, the legislature failed to implement it.

III. State Retail Markets

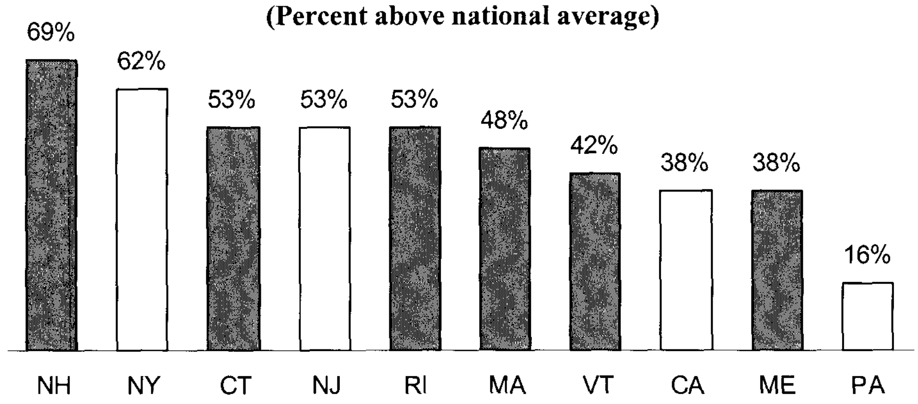
Five of the six New England states initiated electric industry restructuring at the retail level in the late 1990s – a process that continues to this day. This section provides an overview of the restructuring process in each state followed by a simplified estimation of the consumer economic impacts that have accrued through 2005. Brief summaries of state mandated consumer funded electricity efficiency and renewable generation programs are included the Appendix.

General

As shown in Figure 4, the key catalyst for restructuring in New England was the persistently high cost of electricity which was both putting the region's industry at a competitive disadvantage and burdening family budgets.

Prior to restructuring, electricity prices in the region were up to 69% above the national average primarily due to the lack of indigenous fuel sources, over dependence on fossil fuel imports, higher than average prices for labor and transportation, and expensive capital investments and IPP/PURPA contracts. Since then (through 2005), the difference between the national average price of electricity and New England's has narrowed in each state (between 4-21%) with the exception of Massachusetts (which increased 3%). The reality of being located at the "end of the energy pipeline" is also evident in Figure 4, as all of the most expensive states except California are located in the northeast.

Figure 4 – Top Ten States with the Highest Electricity Rates (1996)
(Percent above national average)



Source: Energy Information Administration, U.S. Department of Energy

All of the New England states except Vermont initiated restructuring to lower the price of electricity by introducing competition into the electricity generation portion of the industry and by providing customers the opportunity to choose their retail electricity supplier.[45]

It is important to note that there was no federal legislation or national policy framework for retail electricity restructuring – only a series of rulemaking actions by FERC to create competitive wholesale markets and to provide open access to the transmission system. Conversely, a clear national policy was in place for the restructuring and deregulation efforts of other industries including the trucking, railroad, telecommunications, airline and banking industries that occurred over the past 20 years. As a result, the restructuring of the electric utility industry at the retail level has been accomplished on an ad hoc state-by-state basis with inconsistent policies and standards.[46]

While the New England states adopted differing restructuring approaches and timetables, all the state restructuring policies essentially "unbundled" electricity service into three components — generation, transmission and distribution. Generation companies now compete in a deregulated wholesale electricity market, while distribution companies (essentially the remnants of the formerly vertically integrated utilities) continue to operate as state-regulated monopolies. Transmission is regulated by FERC. Distribution utilities are required to procure power from the wholesale market for customers not choosing a competitive supplier. In short, state commissions now regulate only the rates of the distribution companies – approximately 20 - 40% of a customer's bill. Nevertheless, states indirectly impact wholesale market generation infrastructure development significantly through siting requirements and environmental policies.

Common Regional Retail Restructuring Features

Rhode Island and Massachusetts were the first two states in the region to implement restructuring in 1998, followed by Maine and Connecticut in 2000. New Hampshire's electric utilities restructured at different times beginning in 1998 with the largest utility implementing restructuring in 2001.[47] There are several common features, which serve as a platform for assessing and comparing the progress of restructuring within the New England region, which are summarized in Table 4 and discussed below.

- ***Divestiture of Generation Assets/Creation of Merchant Plants:*** To avoid a concentration of market power and to minimize transition costs, most electric utilities were "encouraged", if not mandated, to divest their generation assets in an auction

[45] Vermont is the only state in the Northeast that has not restructured. The Vermont Public Service Board recommended restructuring in 1996. However, a major obstacle was found to be the very high level of stranded costs from must-take power contracts.

[46] Besides the New England states, a dozen others and the District of Columbia have also restructured including New Jersey, Delaware, Illinois, Oregon, Texas, Arizona, Maryland, New York, Pennsylvania, Michigan, Virginia, Ohio.

[47] The New Hampshire Legislature enacted a statute which directed the Public Utilities Commission to develop a statewide restructuring plan to implement electric retail choice for all customers by January 1998. The Commission issued its plan in 1997 although its implementation was slowed by subsequent litigation that constrained the Commission to consider only voluntary filings of settlement agreements or compliance plans. As a result, electric utilities in New Hampshire restructured at different times and in somewhat different ways.

process in exchange for the right to recover "stranded costs" such as capital and contractual costs incurred under the old regulatory system. As a result, most generating facilities now operate on a "merchant basis" and the financial risk has largely, if not completely, shifted from the consumer to the owners of the plants. The Public Service Company of New Hampshire is the only utility within the restructured states that has not divested all of its generating facilities (while it sold its share of the Seabrook Nuclear Power Station, it has not divested fossil and hydropower facilities).

- ***Allowance of Transition Costs into Rates:*** Transition costs (also referred to as "stranded costs") are the generation investments and contractual cost of utilities that were approved by regulators prior to restructuring, which would have been recovered at fixed rates over time under the old regulatory system. Post restructuring, transition costs minus the sale price of utilities' generating plants were allowed to be recovered over time through a consumer bill charge. In many cases, generating plants were sold at above book value prices which reduced transition costs paid by consumers (but may have put the new owners in financial jeopardy as discussed elsewhere in this paper).

- ***Retail Choice of Power Supplier or Standard Offer Service:*** All consumers were given the option to choose their electricity supplier. Those not choosing a retail supplier were provided standard offer service, which is the electricity purchased by local distribution companies on behalf of its customers. The standard offer period was established to allow for the orderly transition from a fully regulated to a more competitive electric industry structure.

- ***Mandated Rate Reductions:*** Three states mandated that rate discounts be incorporated into standard offer service for a set period of time. In Massachusetts, this amounted to a 15% total bill reduction based on 1997 rates adjusted for inflation. In Connecticut, the statute required that standard offer service be 10% below the rates that were in effect on December 31, 1996. In New Hampshire rate reductions were utility-specific averaging about 15% compared to rates prior to restructuring. Rhode Island did not mandate a rate reduction, but required rates to be frozen at 1996 rates. Maine did not require a specific rate reduction.

- ***Consumer-funded Programs for Efficiency and Renewables:*** All the states mandated consumer-funding to ensure electricity efficiency programs continued in the post-restructured markets. Massachusetts, Connecticut and Rhode Island also mandated the development of consumer-funded renewable energy generation development funds. In addition, all the states except New Hampshire required the establishment of renewable portfolio standards to "theoretically ensure" a certain percentage of renewable energy generation would be included in the state's fuel mix. As summarized in the Appendix, these programs are state regulated and are not considered elements of restructured markets (although they can and do influence the overall performance of the markets).

Table 4
Overview of New England State Restructuring Legislation

Legislation (Date of Implementation)	Plant Divestiture [1]	Initial Mandated Rate Caps/ Reductions [2]	Consumer-Funded Programs [3]		Renewable Portfolio Standard [4]
			Electricity Efficiency	Renewable Development	
Connecticut Electric Restructuring Act of 1998 and 2003 (July 2000)	X	10% below 1996 rates, subject to adjustment	X	X	X
Massachusetts Electric Restructuring Act of 1997 (March 1998)	X	15% below 1997 rates, subject to adjustment	X	X	X
Maine Electric Industry Restructuring Act of 1997 (March 2000)	X	None	X	--	X
New Hampshire Electric Industry Act of 1996 (Utility-by-Utility basis from 1998 to 2003)	Partial (nuclear, but not fossil or hydro)	Averaging 15% below pre-restructuring rates	X	--	--
Rhode Island Utility Restructuring Act of 1996 (January 1998)	X	Frozen at 1996 rates, subject to adjustment	X	X	X

(1) To avoid a concentration of market power and to minimize transition costs, electric utilities were encouraged or mandated to divest or sell their generation assets (power plants) according to differing timeframes established by the states.
(2) Some states mandated rate reductions or price caps to ensure consumer savings during the transition to full retail competition and to insulate consumers from volatile wholesale market price fluctuations during the initial stages of competitive market development. The expectation was that a majority of customers would eventually switch to competitive suppliers by the end of the rate reduction period. When this did not occur in some states, these periods were extended.
(3) These programs differ by state and are funded through special charges on all consumer electricity bills.
(4) Requires a certain percentage of electricity supply to be provided by renewable generation sources – which differ by state.

Retail Marketplace Consumer Prices

Retail Pricing Drivers and Assessment. Through state administered rate reductions and utility supply procurement requirements and competitive wholesale market forces, all classes of electricity consumers have benefited economically from restructuring. Throughout the standard offer service periods, electricity rates in several states decreased or were kept fairly stable despite unprecedented increases in the cost of oil and natural gas through long-term, fixed-priced contracts that utilities negotiated (fuel price adjustments were passed on to customers in some states with the approval of state regulatory commissions).

Quantifying the economic impacts of electricity restructuring is not a simple exercise – given the diverse factors that should be considered (such as environmental regulations, fossil fuel prices, wholesale market rules and procedures, increased electricity demand, etc.) as well as a prognostication of what retail prices would have been under a continued regulated industry. To date, such an analysis has not been undertaken for New England and those performed by individual states in the early years of restructuring are now outdated.

First order calculations were performed from two different perspectives – both of which include an indeterminate amount of savings from the wholesale markets (see previous discussion in Section II) that were passed on to the retail market:

- *Region-wide estimation.* On a nominal basis, New England-wide savings were estimated by comparing the actual weighted average regional retail rates as reported by the U.S. Energy Information Administration against a projection of what they would have been under a continued regulated industry structure from 1998 through 2005 (based on where average retail electricity prices were trending pre-restructuring).[48]

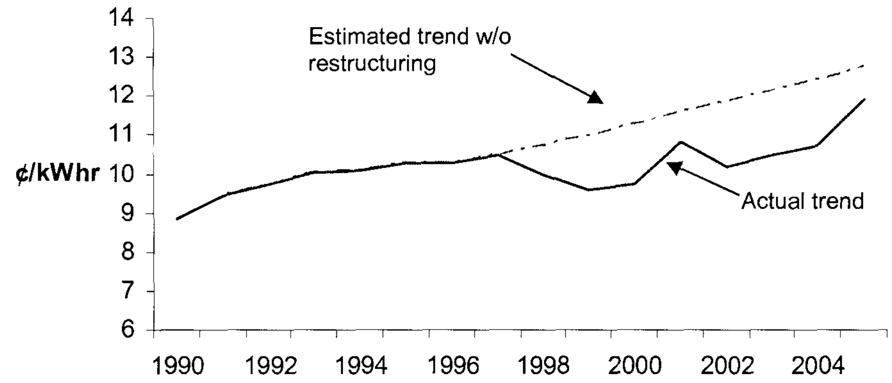
- *State-by-state estimation.* A similar calculation applying the same methodology as above was performed on a state-by-state basis, for the years since restructuring was initiated in each state.

Regional Economic Impact Quantification. Figure 5 shows a comparison of the actual retail prices of electricity in comparison to a projection of what they may have been without restructuring in the region.[49] The projection is both simple and conservative in that it is a continuation of the pricing trends that prevailed during the early and mid-1990s. This estimate quantifies about *$7.6 billion in cumulative, region wide, consumer savings since restructuring efforts began.* Note in Figure 5, that a substantial portion of the savings were accrued in the early years of restructuring as the compounding influence of numerous wholesale market drivers has, at least for the present, changed the course of retail pricing.

[48] Massachusetts, Rhode Island, and a portion of New Hampshire's retail markets were restructured in 1998. For purposes of this analysis, that year marks the beginning of when economic impacts from restructuring started.

[49] The projection of the retail price under continued regulated utility operation is based on the weighted average price trend from 1990 through 1997, after which restructuring was initiated at different times in each state and in the wholesale market in 1999. From the trend, a compounded annual rate of increase in the retail price was calculated at 1.6% and linearly projected forward. Given all of the external factors that have influenced the market since 2000, this projection was considered conservative.

Figure 5 – Average New England Retail Electricity Rates



Source: Energy Information Administration, U.S. Department of Energy

State-by-State Economic Impact Quantification. Summarized below are the estimated economic impacts from restructuring using the same methodology discussed above for the period of retail restructuring in each state. Notwithstanding the difference in electricity demand between the New England states, the spread of savings across the region is significant and reflects the ad hoc basis in which restructuring was implemented.

The savings range from about $3.4 billion in Massachusetts to slightly better than "break even" in Maine. Savings for Vermont were also calculated as that state has benefited from wholesale market savings as well as other asset divestitures as discussed below. Combined, state cumulative savings total about $6.5 billion, which is not surprisingly different (about 15%) than the regional estimate presented above given the differences in timeframes and estimated trend calculations (before restructuring). The regional and total state savings values are close enough, however, to provide some measure of confidence that consumers have accrued a significant amount of savings from electricity industry restructuring.

- ***Massachusetts:*** Consumers on standard offer service were guaranteed a 15% savings from 1997 electricity prices (off the entire bill adjusted for inflation). From 1998 through 2000, for example, average electricity rates in the state decreased each year.[50] Thereafter, state regulators allowed standard offer prices to be adjusted to include wholesale market price increases. Over the 7-year transition period from 1998 to 2005, there were significant savings for consumers who stayed on standard offer service for either part or all of the period. Massachusetts consumers in total have saved about $3.4 billion.[51]

[50]Average electricity rates in Massachusetts decreased from 10.48 cents per kWh in 1997 to 8.99 cents per kWh in 1999.

[51] The projection of the average retail price under continued regulated utility operation is based on the price trend from 1990 through 1997 reported by the U.S. Energy Information Administration (EIA). An annual rate of increase in the retail price was calculated at 1.6% beginning in 1998 and linearly projected forward. Savings were based on total retail sales during that period reported by EIA.

Connecticut: The restructuring statute required that utility standard offer service be set at 10% below the 1996 rates and remain at that level from 2000 until year-end 2003. A "retail adder", that is, an estimate of the cost that retail suppliers would incur to provide electric service to each class of consumer was added to this price (about one cent per kWh). The Revised Electric Restructuring bill signed into law in 2003 created the Transitional Standard Offer (TSO) beginning in 2004 through December 2006, which required utilities to rebid their supply contracts. The TSO does not include the "retail adder", but does include federally mandated congestion charges (from the implementation of SMD in the wholesale markets discussed in Section II).[52] Between 2000 and 2005, it is estimated that consumers have saved between $700 million and $1.5 billion from restructuring.[53] This wide range reflects additional consumer savings from electricity rate decreases that occurred a few years prior to retail competition initiation – reductions that are likely attributable to the initiation of the competitive wholesale market in 1999 and utility cost cutting measures implemented in anticipation of restructuring.[54]

- ***Rhode Island:*** While there was no mandated reduction, the standard offer was initially set to equal the price of electricity paid by customers in September 1996, decreasing average retail rates through 2000.[55] Thereafter, Rhode Island regulators approved standard offer rate increases for inflation and wholesale market adjustments. Between 1998 and 2005, it was estimated that consumers saved approximately $610 million.[56]

- ***Maine:*** The state's restructuring legislation did not mandate price caps or rate reductions. The Maine Public Utilities Commission (PUC) initiated a bidding process to choose firms for securing utility standard offer service. At times, the PUC refused to accept bids that would have resulted in higher rates. Therefore, consumer savings have been accrued as a result of state regulatory intervention – and from wholesale market efficiencies reflected in the market-based contracts. Average retail electricity rates went down during the first year of restructuring then increased in 2001 and 2002 – most likely from natural gas price increases – and then dramatically decreased through 2005. Maine in general has lower wholesale costs than other zones in New England (see Section II on

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[52] "Docket No. 05-11-05, DPUC Monitoring the State of Competition in the Electric Industry," February 22, 2006.

[53] The projection of the average retail price under continued regulated utility operation is based on the price trend from 1990 through 1999 reported by the U.S. Energy Information Administration (EIA). An annual rate of increase in the retail price was calculated at 1.8% beginning in 2000 and linearly projected forward. Savings were based on total retail sales during that period reported by EIA.

[54] Average retail electricity prices in Connecticut decreased from 10.52 cents per kWh in 1997 to 9.52 cents per kWh in 2000 – and remained at approximately that price level until 2003 when adjustments for wholesale market changes were made (when utilities rebid supply contracts) and congestion costs where added due to implementation of SMD in the wholesale market.

[55] Average retail electricity prices decreased in 1998 from 10.7 cents per kWh to 9.59, and again to 9.02 cents per kWh in 1999.

[56] The projection of the average retail price under continued regulated utility operation is based on the price trend from 1990 through 1997 reported by the Energy Information Administration (EIA). An annual rate of increase in the retail price was calculated at 1.2% beginning in 1998 and linearly projected forward. Savings were based on total retail sales during that period reported by EIA.

locational marginal pricing). Over the entire period since restructuring, consumers savings are estimated to be about "break even".[57]

- ***New Hampshire:*** Utilities provided savings of about 15% compared to pre-restructured rates. Public Service of New Hampshire (PSNH), the state's largest utility, also wrote off $350 million of its capital investment as part of restructuring. These rate and utility cost reductions decreased average retail electricity prices to below pre-restructuring levels from 1998 until 2003. Between 1998 and 2005, it is estimated that consumers saved an estimated $950 million.[58] This savings is visibly disproportionate to those realized by other New England states, but appears to be valid. As earlier discussed, this estimation is based on the "electricity price trend" just prior to restructuring. New Hampshire pre-restructuring price trend was higher than other states because its consumers were absorbing Seabrook's construction costs as well as those associated with the bankruptcy of PSNH in the 1990s.

- ***Vermont:*** While the only New England state that has chosen not to restructure, Vermont does participate in the region's wholesale market and has economically benefited from efficiencies cited in Section II. In addition, more than 50% of the generating capacity serving the state is from the Vermont Yankee Nuclear Plant – which under a sales agreement with Entergy in 2002 agreed to lower prices for Vermont consumers through the completion of its operating license. Since the competitive wholesale marketplace was launched in 1999, Vermont consumers realized estimated savings of about $77 million.

The expiration of state administered retail rate reductions and rate freezes in some states combined with wholesale market price increases caused retail rates to sharply increase throughout the course of 2005. Policymakers in some states are now re-examining both their goals and the mechanisms available to meet those goals. Today, consumer retail prices are in most, but not all, instances subject to the forces of the wholesale markets.

Accounting for Inflation. Another method of assessing the economic impacts of restructuring is to compare the average retail prices of electricity in constant dollars over a period of time that reflects a mirror image of the years before and after restructuring. In other words, for Massachusetts, the mirror image would reflect the average price of electricity in constant dollars over the eight years immediately before restructuring (1990 through 1997) in comparison to the first eight years just after it was initiated (1998 through 2005).

As shown in Figures 6 through 10, average *real* retail rates in the five restructured New England states comparatively declined by 7 to 18%.

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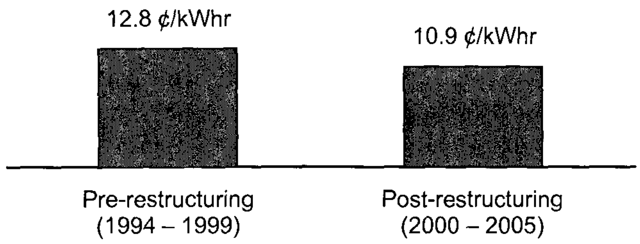
[57] The projection of the average retail price under continued regulated utility operation is based on the price trend from 1990 through 1999 reported by the Energy Information Administration (EIA). An annual rate of increase in the retail price was calculated at 1.1% beginning in 2000 and linearly projected forward. Savings were based on total retail sales during that period reported by EIA.

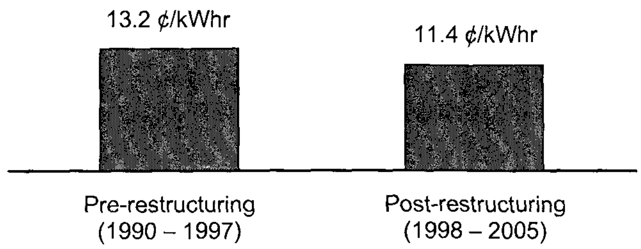
[58] The projection of the average retail price under continued regulated utility operation is based on the price trend from 1990 through 1997 reported by the Energy Information Administration (EIA). An annual rate of increase in the retail price was calculated at 2.7% beginning in 1998 and linearly projected forward. Savings were based on total retail sales during that period reported by EIA.

Figure 6 – Connecticut Inflation Adjusted Average Retail Electricity Prices (15% reduction)



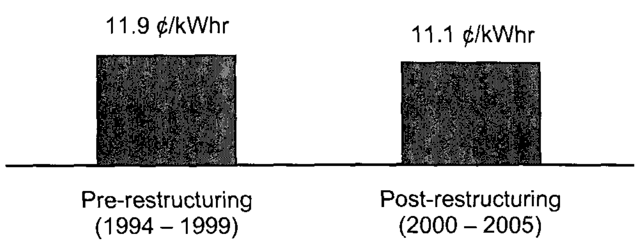
Source: Energy Information Administration, U.S. Department of Energy

Figure 7 – Massachusetts Inflation Adjusted Average Retail Electricity Prices (14% reduction)



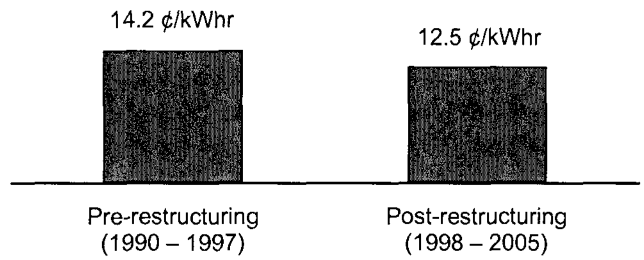
Source: Energy Information Administration, U.S. Department of Energy

Figure 8 – Maine Inflation Adjusted Average Retail Electricity Prices (7% reduction)



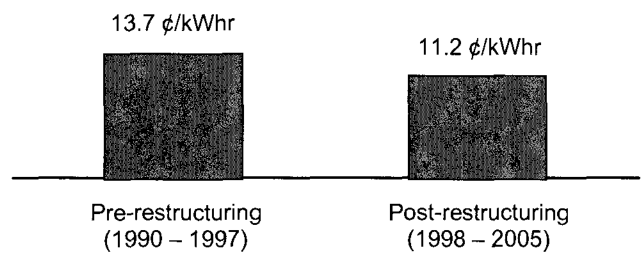
Source: Energy Information Administration, U.S. Department of Energy

Figure 9 – New Hampshire Inflation Adjusted Average Retail Electricity Prices (12% reduction)



Source: Energy Information Administration, U.S. Department of Energy

Figure 10 – Rhode Island Inflation Adjusted Average Retail Electricity Prices (18% reduction)



Source: Energy Information Administration, U.S. Department of Energy

Comparison of Economic Impact Assessments. The above findings are reasonably consistent with recent reports that have quantified the impacts of wholesale market deregulation and state restructuring on consumer prices:

- ***Cambridge Energy Research Associates (CERA):*** "U.S. residential electric consumers paid about $34 billion less for the electricity they consumed over the past seven years than they would have paid if traditional regulation had continued" without competition. On average, CERA found U.S. *real* [electricity] prices were 16% lower during the seven years of the electric restructuring era than during the previous seven years of the regulated era after adjusting for inflation.[59] This estimate by CERA closely matches the average reduction that was calculated for Massachusetts, Connecticut and Rhode Island.

[59] "Beyond the Crossroads: The Future Direction of Power Industry Restructuring", Cambridge Energy Research Associates, October 2005.

- ***New York Public Service Commission:*** A self produced report found that the total inflation adjusted electric price for a typical residential retail customer in New York including supply and delivery charges has dropped by an average of 16% between 1996 and 2004.[60] This reduction also closely matches the average reductions estimated for Massachusetts, Connecticut and Rhode Island – another reasonable comparison given the close proximity of the states.

- ***Global Energy Decisions***: "Competitive wholesale power markets in the Eastern Interconnection (comprising a significant area containing eight of the nation's ten North American Electricity Reliability Councils) produced over $15 billion in consumer savings during 1999 – 2003, compared to what would have realized under the traditional regulated utility environment without competition". This study found the operating efficiency of power plants to increase dramatically – from reduced refueling outages, improved capacity factors and reliability – providing substantial economic benefits – similar to those discussed in Section II regarding New England's increased wholesale market efficiencies.[61]

- ***Associated Industries of Massachusetts***: Focused on a single state, this report (covering the period through 2004) found that passage of the Massachusetts Electricity Restructuring Act in 1997 was steadily leading to significant economic benefits for all classes of consumers – particularly for those who stayed on standard offer service for either part of or all of the seven year transition period – with estimated savings of at least $2.3 billion. Factoring in 2005 savings as well as those attributed to all consumers from increased efficiencies of the wholesale markets since the competitive markets were introduced in 1999, total savings closely match the $3.4 billion savings estimated for all Massachusetts consumers above.[62]

Retail Market Competition and Consumer Choice

Vibrancy of Competition & Choice. A key goal of restructuring was to provide consumers with "choice," which is the option to purchase electricity from a competitive supplier. The states that initiated restructuring opened up electricity markets to competitive suppliers under the premise that competition would benefit all classes of consumers through better prices (as discussed above), services and technologies. Since restructuring, the level of competition remains decidedly limited in the residential sector as shown in Tables 5 and 6 with more robust competition in the commercial and industrial sectors.

[60] "Staff Report on the State of Competitive Energy Markets: Progress to Date and Future Opportunities", March 2006.

[61] "Putting Competitive Power Markets to the Test, The Benefits of Competition in America's Grid: Cost Savings and Operating Efficiencies", Global Energy Decisions, LLC, July 2005.

[62] "Electric Industry Restructuring in Massachusetts", prepared by Polestar Communications & Strategic Analysis for The AIM Foundation, December 2005.

Table 5
Competitive Generation Service as a Percent of Retail Customers

State	Number of Customers on Competitive Supply			Total Customers
	Residential	Commercial	Industrial	
CT [63]	37,268	302		37,570 (2%)
MA [64]	188,618	52,902	4,364	245,884 (9%)
ME [65]	3,277	3,077	382	6,736 (1%)
NH [66]	Limited, but increasing (no state tracking)			
RI [67]	178	2,767		2,945 (<1%)
Source: State Department of Public Utilities Commission Websites				

Table 6
Competitive Generation Service as a Percent of Retail Load

State	Percent of Retail Load on Competitive Supply			Total Load
	Residential	Commercial	Industrial	
CT	3%	3%		3%
MA	8%	34%	82%	43%
ME	1%	36%	80%	38%
NH	Limited, but increasing (no state tracking)			
RI	<1%	10%		10%
Source: State Department of Public Utilities Commission Websites				

It appears more medium and large industrial and commercial customer load is being supplied by competitive suppliers. Throughout the region, residential and small business consumers have had the opportunity to choose suppliers, but stayed with their utility supplier due to a lack of offers from suppliers or uncertainty regarding the outcome of change in supplier.

For residential and small business consumers, the direct savings from retail competition have thus far proven to be insignificant as the price differential offered by competitive suppliers has not been substantial enough to prompt switching. According to a report issued by the National Council on Electricity Policy in 2003, the average residential consumer would have then saved about $8 a month by switching providers – which is apparently below their threshold to undertake action.[68]

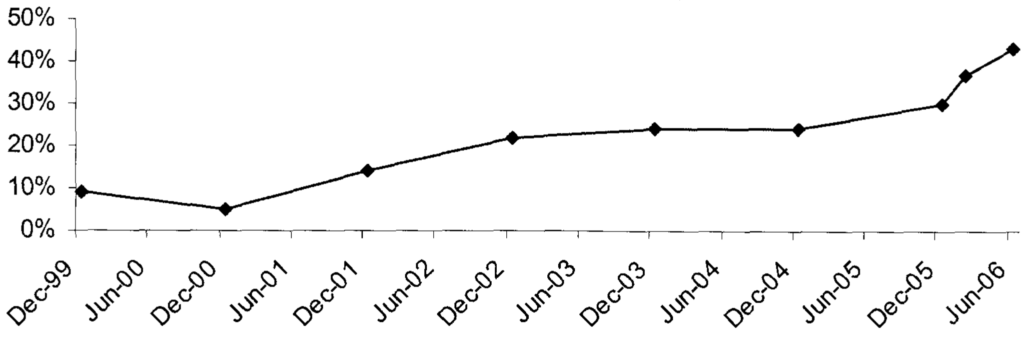
[63] "Docket No. 05-11-05 DPUC Monitoring the State of Competition in the Electric Industry", State of Connecticut, Department of Public Utility Control, February 10, 2006. Data is thru 12/05.
[64] Massachusetts Division of Energy Resources, Electric Customer Migration Data, July 2006.
[65] Maine Public Utilities Commission, Electric Customer Migration Data, September 2006.
[66] New Hampshire Public Utilities Commission does not currently track customer migration statistics.
[67] National Grid, State of Rhode Island Quarterly Report, Open Access Customer Data, March 2006.
[68] "The Challenge of Energy Policy in New England", Federal Reserve Bank of Boston, March 2006.

Retail Market Development. Massachusetts and Maine have the greatest percentage of consumers who purchase electricity from competitive suppliers – with competitive supply in those states serving well over a third of total retail load (Table 6). Rhode Island has lagged behind, and competition is so far very limited in Connecticut and New Hampshire, but there are indications that some customer switching is beginning to occur as transition services in those states either recently expired or soon will.

- ***Massachusetts:*** From the onset of restructuring, Massachusetts experienced a somewhat robust competitive market for large customers, but a rather limited one for smaller customers until the expiration of the standard offer service in March of 2005. Within several months of the standard offer service expiration in March 2005, the number of customers purchasing electricity from competitive suppliers more than doubled. As shown in Figure 11, the percentage of load served by competitive suppliers has increased. About 80% of the state's large industrial load is now supplied by competitive suppliers along with about a third of all medium-sized load. There are 34 competitive suppliers registered with the Department of Telecommunications & Energy.[69]

  While only 8% of residential load is served by competitive suppliers, Massachusetts has had some success (as has Ohio as further discussed below) with customer aggregation. The Cape Light Compact is a municipal aggregator that has assembled the electricity demand of approximately 45,000 consumers in 21 towns on Cape Cod and Martha's Vineyard and contracts for supply through competitive bids.[70]

Figure 11 – Massachusetts' Percent of Load Served by Competitive Suppliers



Source: Massachusetts Division of Energy Resources, Customer Migration Statistics

- ***Maine:*** A consistent level of supply served by competitive suppliers has been maintained since the start of retail choice as shown in Figure 12. The Maine Legislature did not mandate standard offer rate reductions, so retail prices were closer to wholesale market prices at the outset – making it easier for suppliers to compete.

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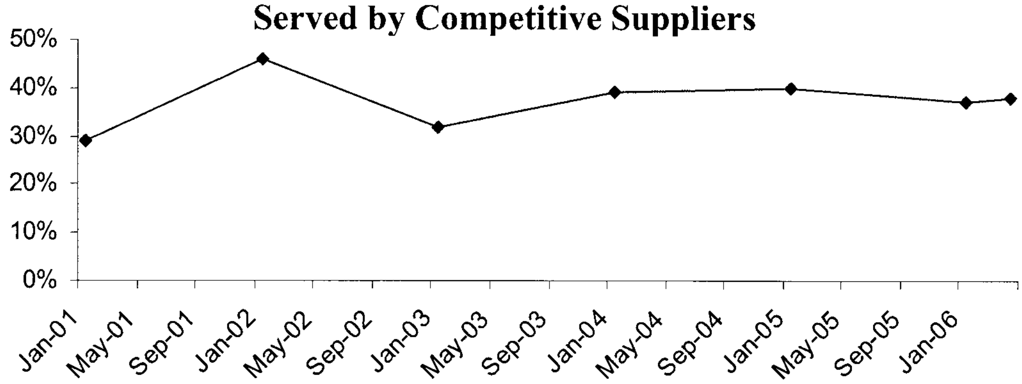
[69] Massachusetts Department of Telecommunications & Energy, List of Competitive Suppliers.
[70] The Cape Cod Light Compact Website, www.capelightcompact.org

There are currently 40 competitive suppliers registered with the Maine Public Utilities Commission. Approximately 80% of the state's industrial load is served by competitive suppliers as is more than a third of the state's commercial load. While competition in the residential market has been limited, aggregation of select customer groups is underway and some 2,000 customers are enrolled in a "Green Power" supply program.

Figure 12 – Maine's Percent of Load Served by Competitive Suppliers



Source: Maine Public Utilities Commission

- ***Connecticut:*** There is limited retail competition in Connecticut – fewer than 2 percent of consumers have switched (comprising about 3% of total retail load).[71] The transitional standard offer (TSO) will expire on December 31, 2006 with utilities then providing standard service to small customers and "supplier of last resort" service to large commercial and industrial customers. In procuring power for small customers, utilities are now charged with smoothing out market volatility. Prices for large customers "must reflect the full cost of providing power on a monthly basis" (no more than quarterly for small customers).[72] Given these pending changes, there are indications that migration to competitive suppliers is beginning to occur. [73]

  Currently, there are fourteen retail suppliers licensed in Connecticut – six of which are actively serving customers. Two offer "green power" through Connecticut's Clean Energy Options Program, which was established by the Connecticut General Assembly in 2004 as an add-on to incumbent utilities' transitional standard offer service, but so far less than 1 percent of consumers are participating in the program.[74]

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[71] There are differing reasons on why retail competition has not progressed in the state – some of which include wholesale market flaws, long-term utility supply contracts, low fixed standard offer prices – which are discussed in Docket No. 05-11-05, DPUC Monitoring the State of Competition in the Electric Industry, State of Connecticut Department of Utility Control, February 10, 2006.

[72] Docket No. 05-11-05, DPUC Monitoring the State of Competition in the Electric Industry, State of Connecticut Department of Utility Control, February 10, 2006.

[73] Constellation NewEnergy, for example, recently signed contracts to supply electricity each month to 44 members of the Manufacturing Alliance of Connecticut through 2008 as well as to the Connecticut Consortium, a group of 68 school districts and municipalities.

[74] Docket No. 05-11-05 DPUC Monitoring the State of Competition in the Electric Industry, State of Connecticut, Department of Public Utility Control, February 10, 2006. Data is thru 12/05.

➢ ***Rhode Island:*** There has been limited customer switching to competitive suppliers, almost all of which has been done in the commercial and industrial sectors, comprising approximately 10% of the load of those sectors combined. Ninety-nine percent of customers continue to purchase electricity from local distribution companies. With regulated standard offer service not scheduled to expire until 2020, it is unlikely that this situation will substantially change in the near-term.

➢ ***New Hampshire:*** No customer migration statistics are currently compiled by the state as minimal customer switching to competitive suppliers has occurred. However, according to the Public Utility Commission, there are indications that customer switching to competitive suppliers is gaining momentum among large customers as transition standard offer service offered by Unitil and Granite State recently expired.[75] Some large commercial and industrial consumers have noted that they prefer the tailored contracts offered by competitive suppliers compared to utility "one-size-fits-all" approach to service.[76] There are five competitive suppliers registered with the New Hampshire Public Utilities Commission.

Retail Competition in Other States. New England's experience with retail competition is similar, and in some cases, better than other restructured states. For example, the customer switching statistics for New York are similar to those of Massachusetts' – 7% of residential customers have switched to competitive suppliers and 43% of commercial and industrial customers. And with 58% of large non-residential load on competitive service, New York is viewed as having succeeded in building a market for competitive service.[77] In New Jersey and Michigan, total consumer load served by competitive suppliers is 15 and 12%, both lower than Maine and Massachusetts.

The more successful states have taken different approaches to develop their retail markets. Ohio's legislation emphasized the establishment of municipal aggregation, which allows a municipality, county or other local branch of government to assemble the electricity demand of all or a part of the consumers and contract for supply through a competitive bid process. Citizens of the aggregating entity become part of the buying group unless they "opt-out".[78] This has resulted in more than 20% of Ohio's residential consumers purchasing electricity from competitive suppliers through aggregators.

Texas is generally viewed as among the most successful state in terms of developing a competitive retail marketplace.[79] Since retail markets opened in 2002, at least 15% of residential, 20% of commercial and 38% of large consumers have switched to competitive suppliers. Texas adopted a retail competition program modeled after the one in United Kingdom

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[75] Telephone discussion with New Hampshire Public Utilities Commission staff, May 4, 2006.
[76] "New Hampshire's Competitive Market is Taking Off", Restructuring Today, April 20, 2006.
[77] "Retail Electric Competition in New York", the Analysis Group for Constellation New Energy, August 2005.
[78] "A Test of the Results of Electricity Deregulation", Wall Street Journal, March 1, 2005.
[79] A study by the Perryman Group titled "Electric Competition: Four Years of Cost Savings and Economic Benefits for Texas and Texans", April 2006, concluded that since the introduction of retail competition in Texas' electric market, Texans have realized substantial savings compared to what they would have paid in a regulated environment – approximately $3.6 billion in 2005 alone.

wherein utility transitional service is set at prices at or above wholesale market levels – creating sufficient economic margins to allow suppliers to be competitive. The Texas model also provides utilities with incentives to shift retail customers to competitive suppliers.

IV. Infrastructure in Restructured Markets

The future performance of the region's competitive markets is dependent on the availability of adequate infrastructure. Yet, for at least the remainder of this decade, New England faces an infrastructure shortfall in maintaining a reliable and affordable supply of electricity, which is vital for economic growth and prosperity.[80] Specifically, the region as a whole needs additional supply to keep pace with increasing electricity demand. Moreover, the region has become heavily dependent on natural gas to fuel electricity generating plants and seems poised to become even more so even though supplies of this commodity are not keeping pace with demand.

Several unique characteristics of electricity as an industry and commodity have contributed to this situation. Infrastructure investment ideally should be prompted and guided by wholesale markets but is often driven by individual state regulations and influenced by retail market programs (mandated by state legislatures). In addition, even in a properly functioning electricity market, the time required for traditional market forces to adjust a supply and demand imbalance may not be quick enough to maintain consumer and political leader confidence in reliable supply of electricity.

As a commodity, electricity must be generated simultaneously with demand – which fluctuates constantly. As a result, additional, or reserve, capacity must be available to compensate for planned and unpredictable generating plant outages, as well as spikes in demand. In short, the unique characteristics of electricity provide challenges unlike any of the other industries that have been deregulated and it is not surprising that some intervention to assure adequate infrastructure is needed.

This paper makes no explicit recommendations regarding the type or magnitude of intervention needed. Rather it highlights the challenges that will undoubtedly drive intervention. Generally, it appears that political leadership will be required along two fronts: 1) reforms to correct imperfections in the competitive wholesale market operations and; 2) coordination to harmonize policies, programs and regulations among states throughout the region.

Generation Capacity Development

Wholesale Market Imperfections. The region's current favorable supply and hence reliability situation will soon become tenuous because there is a very limited amount of generating plant construction underway and peak demand is increasing by about 500 MW per year.[81] There <u>appears</u> to be several reasons for this pending imbalance between supply and demand which include the lack of market signals and incentives to prompt the construction of additional generating capacity before it is actually needed, and the inability of some generating plants to recover their fixed costs (and thus, the prevalence of RMR agreements in Connecticut and Massachusetts).

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[80] Transmission is also a serious infrastructure issue but was addressed in Section II. Moreover, there has been clear progress in addressing this infrastructure issue in comparison to those involving generating capacity and fuel diversity.

[81] The approximate equivalent of one new power plant a year.

The intent of the recently FERC-approved "Forward Capacity Market" (formerly LICAP) settlement is to promote investment in new and existing generating resources – and help mitigate the issues listed above. Under this mandated market structure, ISO New England will project the needs of the grid three years in advance and subsequently hold an annual auction to purchase capacity resources to satisfy them – to include new and existing generating plants, alternative generating sources as well as demand-response assets. ISO New England estimates the first forward capacity auction will be held as early as February 2008 with the resources being paid in 2010. In the interim, the agreement contains a multi-year transition mechanism that will compensate new and existing resources on a monthly fixed basis beginning in December 2006, estimated to increase consumer costs by 5 to 8 percent.[82]

Four New England states (Vermont, Connecticut, Rhode Island and New Hampshire) signed the agreement (Massachusetts and Maine opposed it) which was approved by FERC on June 15, 2006.[83] The total cost is estimated to be substantial and is thus controversial. ISO New England estimated that the original LICAP proposal would cost New England consumers about $8-10 billion between 2006 and 2010. The cost of the FCM is substantially less – estimated at about $5 billion – but still a very significant increase in the price of electricity to consumers.[84]

Many of the details of the FCM still need to be worked out – and will be crucial to ensuring that the goals of the capacity market are attained. Initial market reaction has been positive as proposals for 21 new power plants have come before ISO New England since February 2006.[85] And while it is uncertain how many of these plants will actually be built, they do indicate an increasing amount of certainty in the marketplace in terms of obtaining an adequate return on investment in electric generating resources.

State Environmental Policies. Four of the six New England states signed a memorandum of understanding with three Mid-Atlantic states to develop a regional strategy for controlling greenhouse gas emissions from electricity generation called the Regional Greenhouse Gas Initiative or RGGI.[86] Central to this initiative is the development of a regional cap-and-trade program for carbon dioxide (CO_2) emissions from electricity generating plants in the participating states. Massachusetts has adopted similar greenhouse gas reduction targets, but along with Rhode Island decided not to participate in RGGI.

While RGGI's strategy for controlling CO_2 emissions from generating plants is still under development, model regulations to be implemented in each state have been proposed. Beginning in 2009, emissions of CO2 from power plants in the region would be capped at approximately current levels until 2015. The states would then begin reducing emissions incrementally over a four-year period to achieve a 10% reduction by 2019.[87]

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[82] "Flurry of Power Plant Proposals Offers Hope", *The Boston, Globe*, September 26, 2006.
[83] "ISO New England Announces Broad Stakeholder Agreement on New Capacity Market Design", March 6, 2006.
[84] "What Does the Recent LICAP Settlement Mean for New England", Electricity Restructuring Roundtable, National Grid, April 26, 2006.
[85] "Flurry of Power Plant Proposals Offers Hope", *The Boston, Globe*, September 26, 2006.
[86] These states include: Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont. In addition, Maryland, the District of Columbia, Pennsylvania, the Eastern Canadian Provinces and New Brunswick are observers in the process.
[87] RGGI Press Release, August 15, 2006.

Many energy-companies are calling for greater certainty in climate policy, so that they can better plan for climate-related impacts on electricity prices and investment decisions as these actions are likely to effect existing and future infrastructure development.[88] To comply with RGGI goals, it has been estimated that major change to the existing electricity supply infrastructure will be required, including the construction of significant amounts of new renewable and natural gas-fired generation – which could potentially place unsustainable demands on natural gas supply and its associated pipeline infrastructure.

For example, to meet even the most modest goal considered under RGGI, a recent study sponsored by the Nuclear Energy Institute estimated that 12,800 Megawatts of renewable generation (about 26 projects the size of "Cape-Wind") and 5,000 Megawatts of new natural gas fired generation (approximately 20 new plants) would be required over the next 15-year period. In addition to adding these renewables and new gas-fired resources, the operating licenses for all the region's nuclear plants would need to be renewed. At the same time, many reliable, efficient and economic coal- and oil-fired plants would be forced to close prematurely.[89] Beyond those daunting challenges, actions to meet RGGI goals may be incompatible with the Forward Capacity Market.

Fuel/Resource Diversity

Increasing Dependence on Natural Gas. New England's growing reliance on natural gas to fuel all new generating plants has repeatedly raised concerns about the declining fuel diversity of the region's electricity fuel mix. Almost all of the generating plants built in New England since restructuring have been natural gas-fired because of: their low capital costs, availability of fuel supply and ability to comply with strict federal and state environmental regulations.

As shown in Figure 13, in 2004 (the most recent annual data that is publicly available), 41% of the region's electricity is generated from natural gas. Notwithstanding RGGI requirements or other factors, natural gas is expected to fuel more than 50% of the region's generating capacity within just several years. While even a 50% slice of the fuel diversity pie is nowhere near the 70% that oil accounted for in 1970 (which economically burdened the region during the oil price shocks of the 1970s), it does increase New England's vulnerability to supply disruptions and higher prices than other region's that are considered economic competitors.

According to ISO New England, the region's dependence on natural gas may be even higher in certain areas due to transmission constraints and the unavailability of diverse fuel generating resources. For example, reliance on natural gas for electricity production in the Boston area is forecast to reach approximately 80% by 2010.[90]

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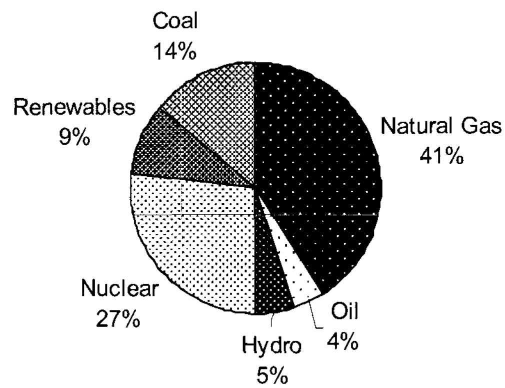
[88] As noted in "New England Energy Infrastructure – Adequacy Assessment and Policy Review", prepared for the New England Energy Alliance by the Analysis Group, November 2005.

[89] New generation estimated to be required to meet the most modest goal analyzed – maintaining CO_2 emissions at the 2005 level under a 10 percent conservation target (of future growth in electricity demand). From "The Role of Nuclear Energy in Reducing CO_2 Emissions in the Northeastern United States", prepared by Polestar Applied Technology, Inc. for the Nuclear Energy Institute, May 2005.

[90] ISO New England Attachment to "New England Natural Gas Infrastructure", Federal Energy Regulatory

Figure 13 – New England's Electric Generation Fuel Mix



Source: ISO New England

As shown in Figure 14, from 1993 through 2003, demand for natural gas in New England increased by 70%, inextricably tying the region's electricity supply, economy, supply of jobs and quality of life to a sufficient supply of natural gas.[91] Almost half of the region's total natural gas consumption is now used to generate electricity – which essentially accounts for all of the dramatic increase in demand of this commodity over the past decade. Lower facility costs, high efficiency technologies, and air quality considerations (to comply with federal and state regulations) have made natural gas the fuel of choice for electricity generation.

The balance between the supply and demand of natural gas in New England is tenuous and the consequences are both tangible and costly. A year ago, the New England Council published a report that concluded that additional LNG facilities are needed in New England before 2010 to meet increasing demand for natural gas and to avert shortages.[92] A similar, but more urgent, conclusion was reached in a report issued by the Alliance later in the same year.[93] The report concluded that natural gas supply/delivery shortages in the region may occur as early as 2007 without additional natural gas supply sources and delivery capacity.

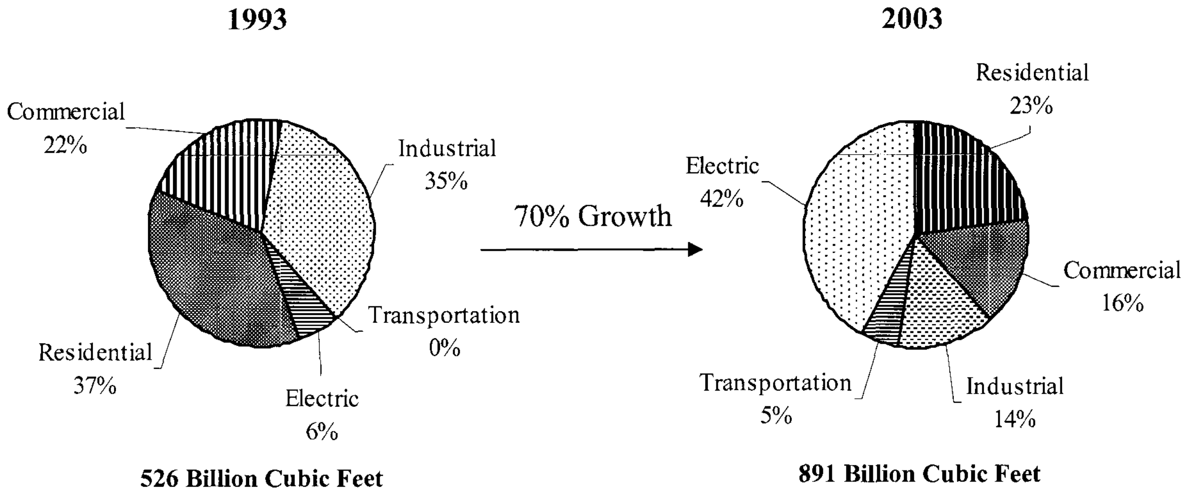
Commission, Staff Report, December 2003.

[91] The figure was not updated to include 2004 data (more recent available). Due to the extreme cold weather that winter, and associated high demand for natural gas for home heating, many of the dual-fueled electricity generating units switched from natural gas to oil. Therefore, the natural gas consumption statistics for the region for that year are uncharacteristically low.

[92] "The Economic Imperative for Additional LNG Supplies in New England", prepared by Polestar Communications & Strategic Analysis for The New England Council, May 2005.

[93] "New England Energy Infrastructure – Adequacy Assessment and Policy Review", prepared by the Analysis Group for the New England Energy Alliance, November 2005.

Figure 14 – New England Natural Gas Consumption Trends



Source: Energy Information Administration, U.S. Department of Energy

Fuel Diversity Options in Restructured Markets. Prudence dictates that New England – individual states and the competitive markets – should work toward a diverse supply of natural gas and electricity generation resources. Fuel supply and generation diversity are desirable as a logical hedge against supply disruptions which protects the reliability of electricity delivery that the region's economy and quality of life depend upon.

Prior to restructuring, a diverse mix of resources also provided economic benefits by reducing the risk of price increases – as generation rates were based on the average cost of all generation. Today, fuel diversity has little effect on electricity prices because natural gas units are "on the margin" and under the wholesale market's reverse auction process set the cost of electricity almost 90% of the time. Natural gas prices have increased by 400% since 1999 and are the key reason for the recent spike in electricity rates noted above. More recently, relief in natural gas prices has resulted in a reduction in wholesale spot market prices. [94] However, the balance between supply and demand of this fossil fuel commodity is tenuous and could periodically and unpredictably put upward pressure on the price of electricity for years to come.[95]

The competitive nature of the wholesale markets under restructuring drives investing to the lowest priced generating fuel – and to projects that are most likely to be approved. Challenging siting processes and a regional bias against certain fuel sources precludes from consideration some technologies that might otherwise be economically viable.

[94] "New England Wholesale Electricity Prices Mirror Relief in Natural Gas Market; Mild Winter, Increased Natural Gas Supply Cited for Lower Power Prices", ISO New England, April 3, 2006.
[95] "The Economic Imperative for Additional LNG Supplies in New England", prepared by Polestar Communications & Strategic Analysis for The New England Council, May 2005.

The November 2005 New England Energy Alliance report cited above stated:

> "Strict reliance on markets without placing a value on diversity or environmental impacts of different supply types may lead to investment in a narrow set of options". Thus, reliance on markets may not solve the diversity issue, since markets do not pre-determine resource mix outcomes. Energy planners, policymakers and developers in the region thus need to carefully evaluate the tradeoffs represented by all demand and supply options available".[96]

Nationally, these concerns have been raised in a recent National Commission on Energy Policy report that addresses the challenges of energy facility siting and permitting and identifies the need for a "wholly different and vastly more appealing siting paradigm". The Commission noted that:

> "While much needed energy production and distribution capacity has been added in many regions of the country over the last decade, other projects face critical siting and permitting constraints. Many of these constraints result from processes in which local concerns trump broader regional or national objectives. Environmental concerns, federal-state regulatory conflicts, aesthetic preferences, highly localized planning processes, investment risks and preferences and regional policy differences have all played varying roles in driving current patterns of infrastructure development and in making it difficult to permit and build major energy facilities in many parts of the United States." [97]

The Commission also noted that in parts of the country where regional planning processes are employed, there is a better chance that energy infrastructure siting decisions will be made.[98]

There are a limited number of options available over the next decade for diversifying the region's fuel mix and supply resources as described below. As noted at the outset, the viability of these options lies along the seam of the forces in competitive markets and state policies and regulations.

- ***Liquefied Natural Gas to Strengthen Supplies of Natural Gas***. Used in New England for decades, LNG currently provides approximately 20% of the region's annual consumption of natural gas increasing to 30% during winter peak demand periods. The Distrigas terminal in Everett – one of four on-shore LNG import facilities in the U.S. – is connected to the interstate pipeline network as well as the local natural gas distribution system. It also directly fuels Mystic Station, one of the largest natural gas-fired generating plants in New England.

  This situation highlights the direction of a competitive market and its benefits to consumers if an adequate supply infrastructure is available. Essentially in the aftermath of restructuring, older and less efficient generating plants at the Mystic site were replaced by a larger and highly efficient facility within the greater Boston area (which by its very

[96] "New England Energy Infrastructure – Adequacy Assessment and Policy Review", prepared by the Analysis Group, for the New England Energy Alliance, November 2005

[97] "Siting Critical Energy Infrastructure", A White Paper Prepared by the Staff of the National Commission on Energy Policy, June 2006.

[98] The Commission will sponsor a series of workshops across the country later this year and into next to address these issues.

location helps alleviate the region's transmission congestion that was discussed earlier in Section II) with considerably fewer emissions. Moreover, by having the generating plant located close to a source of fuel, the "pipeline" was shortened.

The lack of new LNG infrastructure development is not due to a lack of proposals as numerous proposals to develop LNG terminals in New England are currently being processed by federal regulators. The need is both clear and present and the approval process should not be allowed to be short circuited or arbitrarily changed to accommodate special interests – as the consequences of a shortfall will impact the uses of natural gas for space heating and manufacturing as well as for electricity generation.

- ***Clean Coal and Nuclear Technology as Viable Generation Sources.*** The continued efficient operation of the region's coal and nuclear generating facilities is also essential to fuel diversification. These plants are classified as base-load generation – operating 24 hours a day, seven days a week, not changing production to match fluctuating electricity demand which changes from hour-to-hour.

  New England's nuclear plants currently generate more than a quarter of the region's electricity at capacity factors that exceed other technologies and have the lowest production costs of any major source of electricity. They also do not produce emissions that cause smog or acid rain nor generate greenhouse gas emissions. Continued operation of the region's nuclear plants – as well as renewal of their operating licenses – will be essential in achieving RGGI CO_2 reduction targets. In fact, computer models produced for RGGI assume the nuclear plants in the region continue to operate.

  In addition, the region's coal plants have operated reliably – generating about 14% of the New England's electricity. A hallmark of coal is its stability in generating electricity at low prices. In addition, coal can be easily stockpiled at power plant sites, so supply disruptions are not a significant issue. The region's coal plant operators have invested hundreds of millions of dollars in emission control equipment, significantly reducing the region's emissions.

  The recently passed federal Energy Act of 2005 includes financial incentives for new nuclear power plants and clean coal technology that could also assist the region in its fuel diversification efforts. However, given the political environment and historic opposition to these resources, investment in these technologies in New England is not likely in the near future – but should be a consideration in the longer term.

- ***Energy Efficiency as a Resource.*** New England has consistently been a leader in energy efficiency and has achieved greater progress than the nation as a whole, and compared to states with similar economies. As discussed in the Appendix, as part of restructuring, each New England state legislatively mandated funding for electricity efficiency programs through a rate-payer charge, totaling approximately $240 million per year, achieving about 750 million kWh in savings annually. Recent increases in fossil fuel prices, growing concerns about lack of capacity investment (as discussed above), and the need to attain environmental goals should serve as drivers to increase efficiency's role as a "supply" resource.

- ***Renewable Program Project Development Optimization.*** As discussed in the Appendix, to help increase fuel diversity, some of the states have mandated rate-payer funded Renewable Trust Funds to promote the development of renewable energy technologies. In addition, five states have adopted Renewable Portfolio Standards (albeit different ones which make the efforts individually and collectively less efficient with the regional wholesale marketplace) to require electricity suppliers to offer increasing amounts of generation from renewable sources.

  These programs provide needed incentives to investors to make renewable projects economically competitive (although consumers are still paying for the total cost) and help meet environmental goals. As summarized in the Appendix, it is not clear whether these programs are working. Moreover, as ambitious as their goals are, they fall far short of what may well be required under RGGI commitments (as calculated in the NEI study previously referenced).

V. Principles for Future Action

Restructuring remains a work in progress. Two of the three fundamental restructuring goals, to varying degrees at least to date, are being achieved: economic savings for consumers; and increased environmental benefits. The third goal, retail choice of suppliers, is achieving success, but is largely limited to medium and large commercial and industrial customers. It has not been achieved for smaller customers in a meaningful way in any of the states.

- ***Economic Savings:*** Adjusted for inflation, average retail prices are lower – between 7 and 18 percent – than they were prior to restructuring. On a region-wide basis, consumers have saved between \$6.5 and \$7.6 billion since restructuring began. However, more recently, record-high natural gas prices, environmental compliance costs, and transmission congestion costs are reducing these economic benefits.

- ***Environmental Improvement*:** Environmental improvements have resulted from improved operating performance at power plants now owned by competitive power generators, and the significant number of natural gas-fired power plants built during the early years of restructuring – combined with stringent emissions regulations. Emissions of SO_2, NO_x and CO_2 have all declined substantially despite a 25% increase in generation output since restructuring was initiated.

- ***Retail Choice:*** Consumer switching from utilities to competitive suppliers has progressed among medium and large commercial and industrial customers with buying power and knowledge. During the initial years of restructuring, residential and small commercial customers had little incentive to switch as long as utility prices were kept artificially low – or at least stable. Competitive suppliers could not match the price offered by utilities (and they incurred high marketing costs to reach these smaller customer sectors). Even as transition periods end in some states, smaller customers may not perceive the savings offered by competitive suppliers as significant enough to motivate change. These consumers have had choice, but most have chosen to stay with their utility supplier.

With respect to impacts on infrastructure under restructured markets, new generating facilities are not being built to keep pace with increasing electricity demand or in locations requiring additional supply. The reasons are the imperfections in wholesale markets that the pending "forward capacity market" is intended to remedy combined with uncertainties regarding state environmental policies and local resistance to infrastructure development. In addition, the region has become heavily dependent on natural gas to fuel electricity generating plants – substantially decreasing the region's fuel diversity – yet infrastructure to increase or diversify natural and other supplies has been met with political and community opposition.

Political leadership is needed to encourage infrastructure investment and siting by guiding wholesale market corrections and harmonizing state policies, programs and regulations. While this report makes no explicit recommendations, the New England Energy Alliance advocates the adoption of the following principles to guide development of energy policies.

- ***Proactive Policy and Decision Making.*** A reliable and affordable supply of natural gas and electricity is directly linked to the region's economic strength and quality of life. Necessary energy infrastructure, including electric transmission, electric generation, gas transmission, and LNG terminals must be in place when needed. Long lead times for capital intensive projects mean that the region must be proactive to: (1) adhere to, and improve, siting processes; and (2) establish policies that encourage public support and timely private sector investment.

- ***Policy Balancing and Coordination.*** Each state should strive to balance energy, environmental, and economic policies and ensure that long-term benefits exceed short-term costs. Better coordination and efficient execution of energy, economic, and environmental policy among the region's states would reduce consumer costs, increase energy supply reliability, and help assure a level playing field for new infrastructure investment.

- ***Supply Resource Diversity.*** The most reliable and affordable supply of energy is one that is built on ample supplies, flexibility, and diversity. The exclusion of supply technologies through discriminatory policies and actions and failure to allow viable infrastructure projects to be vetted through established federal, state and local review processes makes the region vulnerable to price instability and delivery interruptions, and such exclusionary practices should be eliminated.

- ***Recognition of costs***. The energy industry is among the nation's most capital-intensive. To sustain an affordable and reliable supply of energy to meet consumer needs will require significant investments in all segments of the industry. Regardless of market and regulatory structures, public policy and regulatory actions should ensure that those investments are encouraged and that capital, fuel and operating costs are properly allocated and recovered, as appropriate.

- ***Market Improvement***. Electric utility restructuring and development of competitive wholesale and retail markets in New England can increase efficiency through competition, provide consumers with choice and financial benefits, improve air quality and allocate risks of generation investments to developers. Imperfections in the restructured wholesale and retail markets as they mature are not unexpected and must be addressed by appropriate agencies and organizations.

- ***Demand Side Management Expansion.*** Cost-effective energy efficiency and demand response programs are essential to the success of a comprehensive energy strategy. State policy makers and regulators must continue to support investment for development of economical energy resources including end-use efficiency and demand response mechanisms.

- ***Inter-regional Electric and Gas Interconnection Enhancement.*** In addition to developing and maintaining vital energy infrastructure within New England, the electricity and gas transmission infrastructure with neighboring regions and eastern Canada should be strengthened, adding diversity, flexibility and resiliency to natural or man-made supply disruptions.

Appendix
State Mandated Restructuring Programs

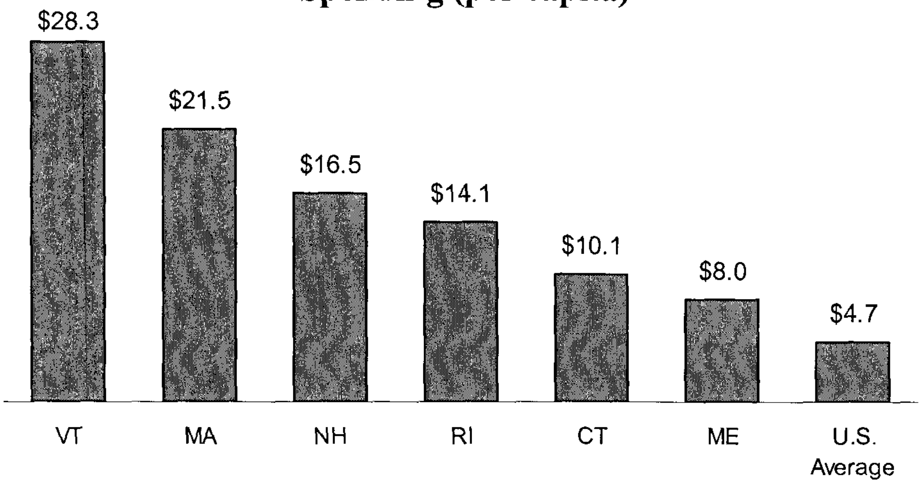
Electricity Efficiency Programs

Electricity efficiency programs were in place before restructuring and have been part of the region's "supply side mix" since the 1970s. They are not part of the wholesale market competitive forces, but can influence the direction and performance of those markets.

As part of restructuring, each New England state legislatively mandated continued funding for electricity efficiency programs through a ratepayer charge of between 0.15 and 0.30 cents per kWh — the equivalent of $9 and $18 a year for the average residential consumer.[99] New England has historically been and continues to be a leader in energy efficiency and outspends most other states on efficiency programs.

As shown in Figure 15, the average national electricity efficiency spending per capita is $4.65, with all of the New England states easily surpassing this marker.

Figure 15
2003 State Rankings by Electricity Efficiency Spending (per capita)



Source: ACEEE's 3rd National Scorecard on Utility and Public Benefits Energy Efficiency Programs: A National Review and Update of State-Level Activity, October 2005

[99] ISO New England operates a demand response program which is designed to reduce generation capacity requirements when the need for electricity is greatest – usually on the hottest summer, weekday of the year. Such actions were not a part of restructuring legislation or rulemaking and are not therefore considered herein.

Results to Date. Approximately $240 million is collected from New England consumers each year for programs that produce electricity savings of about 750 million kWh annually (or enough to power about 125,000 homes).[100] This represents a 1.3% reduction in the region's total consumption of electricity over the course of a year. This effectively has reduced New England's annual electricity growth by about half over the past decade.

Since restructuring was initiated in each state through 2005, approximately $1.7 billion has been cumulatively invested in electricity efficiency programs by New England ratepayers. This has produced cumulative annual savings of over 4 billion kWh, which is enough electricity to power over 650,000 homes. Cumulatively over the 12-year average lifetime of the installed measures, this is enough to displace electricity to power over 8 million homes. Since each state was restructured (through 2004), electric energy efficiency efforts have also avoided the generation of more than 30,000 tons of SO_2, 9,000 tons of NO_x, and 8 million tons of CO_2.[101]

The region's electric energy efficiency programs also reduce total peak demand by about 140 MW per year, which while only less than 1% of the region's total peak demand (which typically occurs on the hottest weekday of the summer), is still to be regarded as important.[102] Peak demand is a key growth parameter – increasing some years by as much as 5%, which significantly drives infrastructure investment.[103]

Renewable Generation Programs

Renewable generation sources have been recognized as desirable and necessary to help diversify the region's supply of electricity. With the exception of hydropower, the relatively high cost of renewable electricity has hindered the development of major generating facilities within the region.

To promote renewable generation investment in restructured markets, state legislatures established two types of programs. The first is a customer-funded program to invest in renewable technology development. The second requires electricity suppliers to ensure that a certain percentage of electricity sold is generated from renewable sources – and if not, they must pay a penalty.

Theoretically, these programs provide needed incentives to investors to make renewable projects economically competitive and help meet environmental goals. Functionally, they lie outside of the wholesale marketplace and operate within retail markets. It is important to note, that some forms of renewable generation have very low capacity factors, so ISO New England must assure adequate backup capacity within the wholesale market to compensate for the unavailability and unpredictability of such sources of supply.

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[100] Assuming residences consume 6,000 kWh per year or 500 kWh a month on average.
[101] Data prepared by Northeast Energy Efficiency Partnership, from state annual reports (www.neep.org).
[102] This represents an average reduction since restructuring was initiated in each state and does not include demand reduction from interruptible load contracts with ISO.
[103] Northeast Power Coordinating Council.

Renewable Electricity (Energy) Funds. Three states – Massachusetts, Connecticut and Rhode Island – have legislatively mandated the use of ratepayer funds for renewable technology development through a surcharge on electricity bills up to $8/year for a typical residential consumer administered by quasi-public agencies in Connecticut and Massachusetts and directly by government agencies in Rhode Island. Since restructuring was initiated in these states, a combined total of over $360 million has been collected from ratepayers.

- ***Massachusetts:*** The Massachusetts Technology Collaborative (MTC), a quasi-public research and development entity, administers the Massachusetts Renewable Trust (RET) Fund which to date has collected over $275 million in consumer funds. Through 2005, the RET awarded more than $240 million to fund over 300 projects including the development of "green schools and buildings", installation of renewable systems in buildings, funding to support renewable companies and the launching of the "Massachusetts Green Energy Fund", a capital fund to support venture investments.[104]

- ***Connecticut:*** The Connecticut Clean Energy Fund (CCEF) is administered by Connecticut Innovations, Inc., a quasi-public agency of the state. The CCEF has collected over $60 million to fund projects including: a green power marketing program; a joint venture to develop portable solar power systems; and supplier efforts to increase consumer demand for renewable electricity. [105]

- ***Rhode Island:*** The first state in the nation to establish a public benefits fund for renewable energy development, the fund is administered by the Rhode Island State Energy Office. Since 1997, approximately $27 million has been collected from consumers to fund a variety of projects. With the passage of the Renewable Portfolio Standards legislation in 2004 (as subsequently discussed), the renewable energy fund budget was reprioritized to shift resources to efforts that will better help electricity suppliers comply with renewable portfolio standards.[106]

While these programs have funded renewable energy installations, provided financial support to renewable companies and small-scale projects, initiated consumer education programs, and assisted in the development of green electricity purchase programs, they have had little direct impact on increasing the number of grid-scale electricity generating renewables projects.

Renewable Portfolio Standards. Massachusetts, Connecticut and Maine included renewable portfolio standard (RPS) provisions in their restructuring laws to require that a specified percentage of electricity supply be provided by qualified renewable generation sources or that electricity distribution companies make an alternative payment that is collected from ratepayers into a designated fund.[107] Rhode Island's Renewable Energy Standard (RES) was

[104] "Annual Statutory Report 2004", Renewable Energy Trust, Massachusetts Technology Collaborative, August 2004 and Massachusetts Technology Collaborative Annual Report 2005.
[105] "Fueling Connecticut's Prosperity", Connecticut Innovations 2005 Annual Report.
[106] "Rhode Island Renewable Energy Fund Strategic Plan, April 1, 2005.
[107] This program is in addition to federal tax credits which, although substantial, have so far proven insufficient to overcome the competitive price shortfall of renewable generation facilities. Twenty states and Washington D.C. have implemented minimum renewable energy standards.

enacted in June 2004 separate from its restructuring legislation and will be implemented in 2007. New Hampshire did not mandate an RPS.

While Vermont has not restructured, a renewable portfolio "goal" was enacted calling for the state's utilities to meet electricity growth between 2005 and 2012 with energy efficiency and renewable resources (capped at 10% of retail sales). If this goal is not achieved by 2012, the policy will become mandatory.

State RPS Comparison. Key differences include the amount of renewables required, how they are defined, and cost recovery mechanisms. These differences make the individual policies less optimal and eliminate a regional synergy among the programs.

- ***Required Renewable Threshold:*** By 2010: Massachusetts requires electricity providers to supply 5% of their portfolio from renewables, with Connecticut requiring 10%, and Rhode Island 4.5%. Maine's portfolio requirement is the highest in the country – requiring electricity providers to supply 30% of electricity from renewable generation. However, this percentage is in fact lower than the available percentage of renewable generation due to the state's broad definition of renewables (as discussed further below).

- ***Defined Renewables:*** Definitions of qualifying renewable technologies vary widely.[108] While landfill gas, solar thermal electric, solar photovoltaic, and wind energy are generally acceptable in all states, the rules vary for other technologies – particularly for biomass, hydropower and fuel cells. Connecticut, for example, accepts only "sustainable" biomass and Massachusetts accepts only low-emission advanced biomass conversion technologies such as biomass gasification. In addition, Connecticut accepts only "small hydropower" up to 5 Megawatts, but Maine allows hydroelectric plants up to 100 Megawatts which includes most of the hydro facilities in the state, and Massachusetts excludes hydropower altogether. For fuel cells, Connecticut and Maine accept those powered by natural gas, while Massachusetts and Rhode Island allow only those powered by renewable sources.

- ***Existing Versus new Renewables:*** All the states except Massachusetts allow existing renewable sources to count toward meeting the legislated goal. Massachusetts allows only renewables installed after December 31, 1997 – and only those located in the ISO New England control area. Beginning in 2010, Connecticut will allow renewable resources to be located in New York or PJM as well as New England.

- ***Cost Recovery:*** Several approaches are used for funding RPS programs, including passing the higher costs directly to all ratepayers, applying a charge on selected categories of sales, or encouraging consumers voluntarily to pay a premium for renewable power (through "green power"). Maine allows RPS costs to be recovered through green power programs, while Connecticut and Massachusetts exclude capacity purchased in green power programs from contributing to RPS requirements. In short, RPS costs can be as much as double the prevailing market price of electricity (since

[108] "State Renewable Energy Requirements and Goals: Status Through 2003", Energy Information Administration, U.S. Department of Energy.

suppliers must pay for both the renewable electricity and RPS compliance costs discussed below).

Compliance. Electricity suppliers in Massachusetts and Connecticut are required to demonstrate RPS compliance by verifying the purchase of renewable energy certificates (RECs) through the New England Power Pool Generation Information System.[109,110] For each Megawatt-hour of renewable electricity generated, the system creates an electronic certificate which may be sold or traded. As a result, suppliers pay for both the renewable electricity and the RECs. Suppliers that fail to comply with the RPS must make an Alternative Compliance Payment (ACP), which is collected from ratepayers, to the state's renewable energy investment fund, currently amounting to about $50/MWh to $55/MWh.

New England currently has approximately 4,250 Megawatts of renewable capacity – most of which is either hydro or biomass.[111] Studies have estimated that an additional 1,000 Megawatts of new renewable capacity will be needed in the region between 2000 and 2010 in order for all the states to comply with their RPS policies. However, between 2000 and 2004, just 73 Megawatts of renewable capacity has been added.[112]

[109] This web-based system administered by an independent transaction processing service provider for the New England Power Pool compiles the production details not only of power generated from renewable resources, but also of all types of electricity generation in the NEPOOL control area.
[110] RPS compliance in Maine is not an issue as there is an overabundance of generation that is qualified as renewable under the state's definition.
[111] 2006 CELT Report, ISO New England, April 2006.
[112] Source: Electric Energy Efficiency and Renewable Energy in New England: An Assessment of Existing Policies and Prospects for the Future May 2005.

A35

Paul Hudson
Chairman

Julie Caruthers Parsley
Commissioner

Barry T. Smitherman
Commissioner

W. Lane Lanford
Executive Director

Public Utility Commission of Texas

February 2, 2006

The Honorable Sylvester Turner
Texas House of Representatives
P.O. Box 2910
Austin, TX 78768-2910

Dear Speaker Turner:

Per your request at the Committee on Regulated Industries hearing on December 12, 2005, please find enclosed a report prepared by Public Utility Commission of Texas (PUC) staff.

As always, we are available if you have any questions about the report's findings or need any additional information.

Best Regards,

W. Lane Lanford
Executive Director

Enclosure

cc: Chairman Phil King
Vice Chairman Bob Hunter
Representative Joe Crabb
Representative Robby Cook
Representative Will Hartnett

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Electricity Pricing in Competitive Retail Markets in Texas

At a meeting of the Regulated Industries Committee of the Texas House of Representatives on December 12, 2005, Speaker Sylvester Turner requested that the Public Utility Commission prepare a report that answers three questions about electricity prices in Texas. The following day, he sent a letter to the PUC Commissioners, setting out his request. This report is the Commission's response to Speaker Turner's request.

Executive Summary

The principal conclusions reached in this report are the following:

- Service options are available to residential customers in many areas of Texas, including the Houston and Dallas-Fort Worth areas, at prices that are significantly below the estimated rates that would have been in effect if regulation had continued.

- A residential customer in the Houston area who switched to a competitive Retail Electric Provider in January 2002 and switched annually thereafter to the lowest-cost provider would have saved about $1450, compared to the estimated regulated rate, over the four-year period retail competition has been in effect.

- Similarly, a residential customer in the Dallas area would have saved over $800 in the last four years by switching annually to the lowest-cost provider.

- There are benefits of competition beyond lower prices for electricity, such as a variety of service and pricing options and efficient mechanisms for promoting renewable energy and energy efficiency.

- Competitive forces resulted in the replacement of older power plants with new, efficient plants, making a major contribution to the reduction of emissions from the electric industry and progress in meeting national air-quality standards in the Houston-Galveston and Dallas-Fort Worth areas.

- The sale of Texas Genco will not adversely affect the Texas electricity market and will not affect retail prices for electricity.

- Rates charged by other utilities in Texas that do not provide retail competition to their customers are not an appropriate proxy for the regulated rates that would have been in effect if competition had not been introduced.

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- Rates charged by other utilities in Texas that do not provide retail competition to their customers are not an appropriate proxy for the regulated rates that would have been in effect if competition had not been introduced.

The tables below summarize the estimated regulated rates, the average of the five lowest competitive prices, the best competitive price, and the Price to Beat for the CenterPoint and TXU service areas.

CenterPoint Energy Service Area	2002	2003	2004	2005
Estimated Regulated Price	**11.0**	**12.0**	**12.8**	**14.0**
Average of Lowest 5 Competitive Prices (actual)	**8.2**	**9.0**	**9.8**	**11.4**
Percentage Difference from Estimated Regulated Price	*26%*	*25%*	*24%*	*19%*
Best Competitive Price	**8.0**	**8.5**	**9.4**	**10.6**
Percentage Difference from Estimated Regulated Price	*28%*	*29%*	*27%*	*25%*
Reliant Energy Price to Beat	8.8	10.3	11.1	12.9

all prices are average yearly price for residential customer using 1,000 kWh per month (cents per kWh)

TXU Electric Delivery Service Area	2002	2003	2004	2005
Estimated Regulated Price	**9.4**	**10.5**	**10.7**	**12.1**
Average of Lowest 5 Competitive Prices (actual)	**8.0**	**8.7**	**9.1**	**10.7**
Percentage Difference from Estimated Regulated Price	*15%*	*18%*	*15%*	*11%*
Best Competitive Price	**7.8**	**8.4**	**8.7**	**10.1**
Percentage Difference from Estimated Regulated Price	*17%*	*21%*	*18%*	*16%*
TXU Energy Price to Beat	8.4	9.6	10.5	11.9

all prices are average yearly price for residential customer using 1,000 kWh per month (cents per kWh)

Question 1: Comparison of Regulated and Competitive Rates

In Speaker Turner's letter dated December 13, 2005, he requested "an 'apples to apples' comparison between the cost of electricity today and the cost if the electric market had not been opened to competition."

Developing estimates of what rates would have been if the retail sale of electricity had remained regulated is fraught with uncertainties. The PUC regards any answer that the agency or others provide as an estimate with a large degree of uncertainty, because of the numerous and inter-related assumptions that must be made to perform the calculation. In view of the resources required to perform this analysis, the calculations are limited to the TXU Electric Delivery and CenterPoint Energy service areas. These are the largest service areas open to competition.

With respect to the cost of electricity in today's market, competitive offers are more representative of the results of introducing competition than the Price to Beat (PTB). The PTB is not a competitive rate; rather, it was intended to be sufficiently above market rates to permit new entry into the market by retail electric providers and to encourage customers to shop. The tables above show the best competitive offer and the average of the five lowest offers available in the market as comparison points. These points of comparison provide representative market prices.

The results summarized in the tables above indicate that the competitive market has provided customers with prices that were significantly below the estimated rates that would have been in effect in a regulated environment. Even customers who did not switch to a competitive rate have benefited from the introduction of retail competition. During each of the years 2002 through 2005, the PTB was lower than the estimated regulated rates in both service areas.

Question 2: Impact of Sale of Texas Genco

Speaker Turner also asked whether the sale of Texas Genco would affect the Texas electric market and electricity prices.

The sale of Texas Genco will *not* negatively impact the Texas electric market and will *not* affect market prices of electricity. In a competitive electricity market, a supplier that does not possess market power does not have the ability to set market prices. Instead, prices are determined by the market forces of supply and demand. The value of assets in this environment is based on expectations about the costs and revenues that an asset will generate over its life. Under regulation, on the other hand, the value of an asset is a key factor that is used by regulators in establishing prices for consumers.

The substantial increase in the price of natural gas over the last several years has increased the profitability of coal and nuclear generation, because of the low and stable prices of coal and nuclear fuel. The result has been dramatic increases in the values of coal and nuclear generation assets. Conversely, if substantial decreases in natural gas prices occurred, the value of solid fuel assets such as coal and nuclear facilities would fall.

Question 3: Current Rates in Non-competitive Areas

Finally, Speaker Turner asked for an analysis and response to Carol Biedrzycki's comparison of the prices of electricity offered by various providers.

Ms. Biedrzycki appears to suggest that deregulating retail rates has resulted in higher rates for customers. The comparative rate information that she provided does not support this conclusion. Rates differed among utilities prior to competition, for a number of reasons, and rates changed in different ways for a number of reasons. One of the biggest factors resulting in the differences in rates and the degree of change in rates is the fuel mix of the generating plants that are used to produce power for customers. Other reasons why the current rates for utilities differ include:

- Different utilities have historically had different rates.
- Senate Bill 7 included a rate freeze that limited the regulated investor-owned utilities' ability to change rates.

Electricity Pricing in Competitive Retail Markets in Texas

Question 1: Comparison of Regulated and Competitive Rates

Speaker Turner's first request was as follows: "Specifically, I am referring to my request for a model that would make an 'apples to apples' comparison between the cost of electricity today and the cost if the electric market had not been opened to competition."[1]

Estimates were made of the cost of electricity for residential customers in the two largest utility service areas in Texas, TXU Electric Delivery Company and CenterPoint Energy. TXU provides delivery service in Dallas-Fort Worth and large parts of North, West, and Central Texas. CenterPoint provides service in Houston and surrounding areas. The estimated cost of electricity under regulation is compared to representative competitive rates in each service area. The PTB is also provided as a reference point, but it is not the appropriate comparison point to the estimated regulated rates, as discussed below. In addition, this response provides a discussion of the differences between a regulated market and a competitive market, information on the benefits of competition, apart from any cost considerations, and a description of the process used to estimate the rates that would have been in effect if electric service had remained regulated. This analysis is limited to residential customers, because both regulated and competitive prices vary widely for commercial and industrial customers based on their size, energy use patterns, their ability to curtail their demand, individual contract terms, and other factors.

[1] This and the other questions are quoted from the letter from Rep. Sylvester Turner to Chairman Paul Hudson, Commissioner Julie Parsley, and Commissioner Barry Smitherman, dated December 13, 2005.

Estimating hypothetical regulated rates for a period of several years is a difficult task at best. The largest component of regulated electricity rates is the cost related to the ownership and operation of generation plants. Consequently, the amount and cost of generation investment and the cost of fuel are the largest drivers of electric utility rates. The statute that established retail competition led to the unbundling of the existing utilities and the entry into the generating sector of new companies that made large investments in new, efficient generating facilities. Apart from the relatively straight-forward task of determining the prices of natural gas and coal, assumptions have to be made about the kinds of power plants that the utilities would have used to produce power for their customers and the costs of the plants. A regulated environment would have resulted in a different set of generating plants, different costs, and a different cost recovery regime than occurs in a competitive market, and these differences have major implications for estimating the price of electricity.

The legislative adoption of retail competition in 1999 resulted in an extraordinary level of investment in new generating facilities in ERCOT that were more efficient in converting natural gas to electricity than many of the plants owned and operated by the integrated utilities. The result was an extraordinary improvement in the overall efficiency of the power plants in ERCOT. If retail competition had not occurred, new investment in power plants would have been required to meet the needs of Texas electricity customers, but the level of investment would have been much lower, and the improvement in overall power plant efficiency would have been much more modest. The implications for electric rates are that more natural gas would have been consumed to meet customers' needs under continued regulation, more aging and inefficient plants would have remained online, and customers' rates would have reflected these higher costs.

Because of the importance of cost recovery related to investment in generation facilities and fuel costs, a discussion on the different treatment of these costs in a regulated world and a competitive world may be helpful.

Comparison of Regulation and a Competitive Market

Competition in the sale of electricity was introduced in Texas in two stages, in the wholesale market in 1995 and in the retail market in 2002. The market changes occurred at a time when the State was facing increasing demand for electricity and the need to build additional power plants. It was also a time when customers were beginning to pay higher electricity prices associated with the completion and commencement of operation of large nuclear-generating plants. One of the major impacts of the introduction of competition was to shift the risk associated with building new power plants from customers to the companies that built the new plants. Billions of dollars were invested to build new plants to meet the needs of Texas customers, and the companies that built the plants bore the risk of recovering the cost of these plants through market-based prices.

In a regulated environment, the risk of investment in new generation facilities rests primarily on customers. The rules of rate regulation require utilities to provide adequate, reliable service to their customers, and rates are set to allow them to recover their prudent investments with a reasonable rate of return. New production facilities are subject to pre-approval and a post-construction prudence review, and in this process the utility must demonstrate that its proposed facility is needed, is the option that will best meet customers' needs, and that the costs were prudently incurred.

In theory, these regulatory approvals would ensure that the utility acquires a facility only when it is needed, selects the most appropriate technology, and manages the construction of the facility to minimize its cost. In reality, a regulatory commission and the parties who participate in these proceedings face significant difficulties in challenging the utility on its choice of technology or its management of the construction process. Additionally, since review of the costs occurs after the fact, significant disallowances may threaten the utility's financial integrity. Because cost recovery is set for the life of the asset, customers are generally locked into paying for the investment, even if subsequent technologies or changes in fuel or energy markets make the investments uneconomic. When utilities in Texas constructed the South Texas Project and Comanche Peak nuclear power plants, the projects experienced significant cost overruns, and the prudence reviews resulted in relatively small disallowances of construction costs. The costs of the South Texas Project are a major component of the stranded costs that CenterPoint Energy and AEP Texas Central Company will be recovering from customers in their service areas.

In a competitive environment, on the other hand, investors in new generation are not assured of the recovery of plant costs from customers. A company that invests in new generating facilities bears the risk that the facility will recover its costs through sales in the market. In ERCOT, as the new generating facilities began operating and retail competition began in 2002, the wholesale market prices for power indicated that these new plants were not making substantial margins on the sale of the power that they produced. Nevertheless, the new, efficient power plants operated, and the market prices were based on their efficiency. In the early days of competition, electricity customers got the benefit of market-priced electricity from these efficient generating plants without paying their full capital costs.

Competition also provides stronger incentives for producers to operate their generating plants efficiently. In a regulated environment, the utility recovers its fuel costs through rates. The regulatory commission periodically reviews fuel costs and power plant operations to ascertain whether the utility has operated efficiently, and it can disallow costs that it concludes are higher than would result from efficient operations. In a regulatory review, the utility has the important advantages of both greater resources and better knowledge of how its plants have operated.

In a regulated environment, there is not a direct connection between efficiency and profitability. If the utility is inefficient, and the regulatory commission is not able to detect the inefficiency, the utility recovers all of its fuel costs and does not experience any consequences from its inefficiency. If the utility is able to increase its efficiency and reduce fuel costs, the commission would reduce the rate, and customers would benefit from the improvement. On the other hand, in a competitive market, the producer's revenue is based on market prices, not commission-established rates, and any increase in efficiency can lower production costs and increase profits. In competitive markets, operators of coal and nuclear power plants have been able to increase the number of annual operating hours of their plants. Because these are plants with low operating costs, increasing the number of operating hours enables the operators to increase their profitability. Thus, profit motivation provides a strong incentive for producers to improve efficiency.

Under regulation, rates are set to recover the utility's investments and expenses from customers by grouping customers with similar characteristics into large classes. For certain expenses, such as fuel, a rate is set based on forecasted costs, and then reconciled with actual expenses at a later date. While this provides a customer assurance of the level of prices for a short period, the customer is required to bear the risk associated with changes in fuel prices. If fuel prices increase, the increases are passed on to customers through a surcharge, and customers have little ability to contract with the utility in a way to obtain price certainty.

Retail competition brings a broader array of pricing options to customers. The Texas retail market is still quite young, but business customers have a number of pricing options, particularly with respect to the allocation of risk of changes in market prices. In the competitive environment, a customer typically can find a price that is fixed for some period of time or a can choose a rate that is adjustable, depending on market conditions, on an hourly, daily, or monthly basis. Changes in market conditions spur REPs to develop pricing options to meet customers' expectations. For example, after the increase in natural gas prices in the late summer and fall of 2005, many retailers and customers expected gas prices to fall, as production was restored at gas production facilities that were taken out of service as a consequence of Hurricanes Katrina and Rita. In this market, some REPs developed pricing plans that gave customers a long-term contract at a rate that could not be raised but could be lowered, if falling gas prices result in lower prices for electricity in the wholesale market. In addition to options related to price risks, an option that is broadly available in the retail market is renewable energy.

Historically, this variety of pricing options has not been available in a regulated environment, because of the difficulty of ensuring fair prices. The retail market ensures, through market forces, that options related to price risk and renewable options are appropriately priced. A regulatory commission typically does not have the resources to assess the costs and risks associated with multiple service options and appropriately establish and modify the prices, based on evolving market conditions. These are valuable options to customers that would be virtually impossible to provide in a regulated environment.

Competition also allows REPs to bundle electric service options with other services in packages that customers find attractive. Competition is in its infancy in Texas, and REPs have focused on establishing their businesses and winning customers. As competition matures, it is likely that REPs will combine electric service with other services in packages that customers find attractive. Indeed, certain REPs are already offering appliance-repair and HVAC-servicing plans that are designed to foster energy efficiency. In an environment in which electricity prices have increased, it seems particularly likely that REPs will offer further energy-efficiency services to help customers reduce their energy costs.

Finally, the implementation of retail competition has provided benefits to society at large. These forces of competition resulted in a significant shift in electricity production away from older, less efficient power plants to new, more efficient power plants. At a time when the State faced a serious problem in meeting national air-quality standards in the Houston-Galveston and Dallas-Fort Worth areas, the new power plants made a major contribution to reducing emissions from the electric industry. Senate Bill 7 included measures that were explicitly intended to contribute to cleaner air. Competition also provided an efficient mechanism for meeting goals for renewable energy and energy efficiency, which have contributed to reducing emissions of nitrogen oxides, one of the precursors for ozone formation. Among the provisions of Senate Bill 7 was a requirement that utilities assess a system benefit fee, which would be used to provide discounts and energy-efficiency improvements to low-income customers. In the four years that appropriations for the low-income discount were made, REPs provided low-income customers over $300 million in discounts.

Method for Estimating Regulated Rates

Estimating the rates for a hypothetical situation that did not occur is a difficult task. The estimate requires information about the costs incurred by utilities and prices for natural gas and coal. Some of these costs are likely to have been the same, whether competition was introduced or not. Other costs are dependent on events that would certainly have been different in a regulated environment, and there may be a large degree of uncertainty about how events would have unfolded.

The other difficulty is the need to simplify the process of estimating rates. Rate cases involve the review of a large volume of information over a period of months and legal and factual arguments among the parties to the rate case over whether some of the expenses that the utility seeks to recover were reasonable and necessary. At the end of the rate case, the PUC decides which expenses are reasonable and necessary and what rate of return is appropriate. This is an event that cannot be replicated in estimating the rates that would have been in effect. The estimate that is provided here is based on the best information that could be gathered in a relatively short time and an assessment of how the utilities might have met their customers' needs.

The methodology used to estimate the regulated rates was to assume that new base rates were set for the two utilities in the 2000-2001 timeframe, and that these base rates would have remained in effect through 2005. It is assumed that rates for the recovery of fuel and purchased power, however, would have been adjusted to match the changes in fuel costs in the market and increased purchases of power to meet the utilities' needs. There are a number of simplifications and uncertainties that are involved in using this methodology that are likely to result in differences from what would have actually occurred, if regulation had continued. For example, a different level of transmission investment might have been required, and the Legislature or PUC might have adopted renewable energy requirements that are not reflected in the estimate of regulated rates that is included in this report. Such uncertainty would be present in any effort to estimate the rates that would have been in effect in a regulated environment.

The starting point for estimating the rates that would have been in effect are the annual reports that utilities filed in the 2000-2001 timeframe. The annual reports are mandated by PURA, constitute an abbreviated calculation of utility costs, and provide contemporaneous information about the utilities' costs. In addition, in estimating the regulated rates, an assessment was made whether the utilities would have needed to acquire additional capacity and energy to meet their customers' needs and whether they would have made investments in pollution control equipment for existing generating plants. Senate Bill 7 required that utilities meet more stringent air pollution standards, but it is assumed that the need to improve air quality in major Texas cities would have resulted in more stringent standards, even if Senate Bill 7 had not been enacted.

This approach assumes that utilities would have generated the electric energy needed to serve their customers first from the fleet of generating plants that they owned before competition began. To the extent that a utility would have needed to acquire additional capacity and energy to meet its customers' needs, it is assumed that the utility would have met this need by buying power from independent power producers through long-term contracts that would provide the seller recovery of the operating and ownership costs of new generating facilities. A detailed description of the method used for estimating the regulated rates is set out in Appendix 1.

Method for Calculating Competitive Prices

Summarizing the competitive prices that actually existed during the last four years is a far more straightforward exercise. The PUC performs a survey of residential competitive offers each month and posts that information on its website. This information provides a historical record of the prices available to customers in the marketplace, and was compiled for the TXU Electric Delivery and CenterPoint Energy service territories for each month in the years 2002-2005. The following are provided as representative competitive prices: an annual average of the five lowest competitive offers each month, an annual average of the best competitive price each month, and an annual average of all of the non-renewable products each month. The average of the five lowest competitive offers removes the effects of renewable energy products, which are priced at a premium to other competitive offers, and avoids over-reliance on abnormally low competitive prices offered by competitive REPs whose business models may have been unsustainable.

The PTB, which is the residential rate for customers who did not switch to a competitive Retail Electric Provider, was not used as the principal comparison rate to the estimated regulated rate. The PTB took effect in January 2002 as a rate that was 6% less than the regulated rates in effect in 1999 (adjusted for 1999-2001 changes in fuel costs), and it can be adjusted up to twice per year based on significant changes in the market price of natural gas and purchased energy, which are highly correlated in ERCOT. The PTB was intended to be, and generally has been, an above-market rate that provides an opportunity for the incubation of new entrants in the retail market during a transitional period. The presence of these new-entrants in turn, gives customers an opportunity to shop for alternate providers. Since 2005, the affiliated REPs have been able to charge prices other than the PTB.

Results

The tables below show the estimated regulated rates and representative competitive prices, in cents per kilowatt-hour on an annual basis, for a typical customer consuming 1,000 kWh each month. The representative competitive prices are the yearly average of the five lowest competitive prices, an average of the best competitive price for each month, and an average of all non-renewable competitive prices. For reference, the average PTB for each year is also shown.

TXU Electric Delivery Service Area	2002	2003	2004	2005
Estimated Regulated Price	**9.4**	**10.5**	**10.7**	**12.1**
Average of Lowest 5 competitive Prices (actual)	**8.0**	**8.7**	**9.1**	**10.7**
Percentage Difference from Estimated Regulated Price	*15%*	*18%*	*15%*	*11%*
Best Competitive Price (actual)	**7.8**	**8.4**	**8.7**	**10.1**
Percentage Difference from Estimated Regulated Price	*17%*	*21%*	*18%*	*16%*
Average all Competitive Prices, excluding renewable products (actual)	**8.1**	**9.1**	**9.6**	**11.7**
Percentage Difference from Estimated Regulated Price	*13%*	*13%*	*10%*	*3%*
TXU Energy Price to Beat	8.4	9.6	10.5	11.9

all prices are average yearly price for residential customer using 1,000 kWh per month (cents per kWh)

CenterPoint Energy Service Area	2002	2003	2004	2005
Estimated Regulated Price	**11.0**	**12.0**	**12.8**	**14.0**
Average of Lowest 5 competitive Prices (actual)	**8.2**	**9.0**	**9.8**	**11.4**
Percentage Difference from Estimated Regulated Price	*26%*	*25%*	*24%*	*19%*
Best Competitive Price (actual)	**8.0**	**8.5**	**9.4**	**10.6**
Percentage Difference from Estimated Regulated Price	*28%*	*29%*	*27%*	*25%*
Average all Competitive Prices, excluding renewable products (actual)	**8.4**	**9.6**	**10.2**	**12.3**
Percentage Difference from Estimated Regulated Price	*24%*	*21%*	*20%*	*12%*
Reliant Energy Price to Beat	8.8	10.3	11.1	12.9

all prices are average yearly price for residential customer using 1,000 kWh per month (cents per kWh)

Competitive prices have generally been substantially lower than the estimated regulated rate, illustrating that customers who elected to switch received substantial savings compared to what continued regulation would have provided. Customers who did not switch also benefited from the introduction of retail competition. The PTB was lower than the estimated rate that would have been in effect under regulation for the entire period from 2002 through 2005.

An estimate was also made of the total amount that a typical residential customer would have paid from January 1, 2002 to December 31, 2005 if regulation had continued. This amount was compared to the electricity costs of a hypothetical customer who switched to a competitive provider on January 1, 2002, and then switched on January 1 of each subsequent year to a lower-cost provider, if there was a lower-cost provider. This calculation did not assume that the rate was fixed, but that the rate changed at the same time that the provider altered its pricing in the market. This analysis indicated that a customer in the Dallas area who evaluated the choice to switch annually would have saved over $800 compared to the estimated regulated rates for the four year period that competition has been available. The customer would have also saved over $540 compared to the PTB over the same period. A customer who acted the same way in the Houston area would have saved $1450 over the four year period from the estimated regulated price, and $640 compared to the PTB. Customers who switched more frequently than annually or entered into a fixed price contract for some duration could have saved even more.

Question 2: Impact of Sale of Texas Genco

Speaker Turner's second request was as follows: "What effect does the sale of Texas Genco have on the Texas electric market and how will it affect electricity prices?"

The sale of Texas Genco will *not* negatively impact the Texas electric market and will *not* affect market prices of electricity. While issues underlying this response are explored in greater detail below, the simple answer is based on the fact that, in a competitive electricity market, a supplier that does not possess market power does not have the ability to determine market prices. This is a consequence of how competitive markets operate, and the fact that the sale of electricity in ERCOT is now a competitive market, in which prices are determined by the market forces of supply and demand. The prices in a competitive market are established in a manner that is markedly different from how they are established in a regulated environment. Under regulation, the value of an asset is a key factor that is used by regulators in establishing prices for consumers.

The question arises, of course, whether the sale of Texas Genco would give the new owner the ability to exercise unreasonable market power and consequently influence market prices in an inappropriate manner. Controlling improper exercise of market power was a matter of significant concern on the part of the Legislature when the retail competition law was enacted in Texas, and the law includes a number of provisions to prevent the accumulation and exercise of market power. The sale of the Texas Genco assets did not result in any increase in market power, because the new owner does not own other generating assets in ERCOT.

It would be expected that the sale of generating assets, such as the sale of the Texas Genco assets, would be at a market-determined price, which would be based on two factors: (1) the expected revenues that could be derived from selling the output at *market* electricity prices and (2) the cost of producing the electricity. In other words, the value is based on the expected profits the asset can generate. In the sale of a long-life asset such as a generating plant, expectations about the profit it might generate over its life would determine its value. For a company like Texas Genco, which has substantial coal and nuclear assets, the focus of an analysis of asset value is on revenue. The costs of coal and uranium fuel have historically been quite stable, but electricity prices in ERCOT (and in general) are more volatile.

Market prices in ERCOT in the near term are driven by customer demand and the price of natural gas. Market prices are established by demand and the deployment of the generating plants in the market to meet the demand. In ERCOT, for most of the hours of the year, the available plants with low operating costs, namely, nuclear, coal, and lignite plants, are fully deployed before the aggregate level of customer demand is met. Additional generating plants fueled by natural gas must be used to meet the aggregate demand. Thus, the market-clearing price is established by gas-fired generating plants. The substantial increase in the price of natural gas over the last several years has increased the profitability of coal and nuclear generation, because of the low and stable prices of these fuels. The result has been dramatic increases in the values of coal and nuclear generation assets. Conversely, if substantial decreases in natural gas prices occurred, they would reduce the value of solid fuel assets such as coal and nuclear facilities.

In the long term, it would be expected that coal and nuclear plants could be built to compete with the existing power plants in ERCOT, and the competitive advantage of the existing coal and nuclear plants would be reduced. Some companies have announced plans to build new coal plants in ERCOT, but there are environmental and financing risks associated with coal and nuclear generation, and the financial sector appears to be skeptical about significant additions of coal and nuclear generation in ERCOT. If new coal and nuclear facilities are built, licensing and construction will take some time. Thus, even in the long-term, ERCOT electricity prices are likely to be highly dependent on gas prices.

In a competitive electricity market, the risk of fully recovering an investment in generation assets falls upon the *purchaser* of the assets, not on customers. This point illustrates a key distinction between regulated and competitive markets: in a regulated environment, the risk essentially falls upon customers, who pay for the asset through rates determined by the rules of cost-of-service regulation. In contrast, in a competitive environment, the risk falls upon the owners of the assets. In competition, any changes in asset value resulting from changes in the market accrue to the owner of the assets. Accordingly, the fact that NRG Energy recently agreed to pay approximately $8.3 billion for Texas Genco does *not* mean that the burden of recovery of this amount falls on the shoulders of customers. Rather, NRG now bears the risk of recovering its investment in Texas Genco, and if the market changes in a way that causes the value of Texas Genco to decline, NRG bears the loss, not customers.

Other Issues Related to a Sale of Assets

To provide greater detail concerning the impact of the sale of Texas Genco, two questions are explored below:

1) Does the sale price of a generation asset drive electricity prices?
2) Does the sale of generation assets bestow upon the purchaser an inappropriate degree of market power and, therefore, the ability to unreasonably influence market prices?

1. Does the sale (and sale price) of a generation asset drive electricity prices?

One of the basic principles for the regulation of rates by a government agency is that customers' prices set by the regulatory agency are based on the cost of providing the service. This basic ratemaking principle allows a utility company to recover the reasonable and necessary expenses of providing the service, plus a return on the investment it has prudently incurred to provide the service. Thus, where assets are used in providing the service to customers, the rates the utility may charge to customers provide it an opportunity to recover the operating costs, including depreciation, and the investment cost, that is, a return on the value of the assets. The costs incurred by the company to acquire an asset are returned to it, over the life of the asset, through the depreciation expense, and a return on the value of the asset is provided to compensate the company for the risks and financial costs that arise because the recovery is spread over the life of the asset. Accordingly, under traditional regulatory laws and practices, the cost of an asset does have a direct impact on the company's regulated rates. For example, if an asset costs $100, this amount will be expressly reflected in the calculation of the depreciation expense and return, amounts that ratepayers pay over the life of the asset. In this regulated context, asset costs drive the prices that consumers pay, and the higher the prudent cost of an asset, the higher the regulated rates will be.

In contrast, in a competitive environment, the reverse relationship holds true. That is, in a competitive environment, asset values are driven by the expected revenues that the owner of an asset can expect to receive from ownership of the asset over its useful life. This relationship is fundamental for the valuation of any type of asset in a competitive market. With respect to the competitive electricity market, this means that market electricity prices, as determined by market supply and demand, are key determinants of the value of an asset. Reports prepared by analysts in the financial sector support the proposition that the value of companies and their assets in a competitive environment is based on expected revenues. For companies in a competitive environment, such reports focus on the fundamentals of supply and demand and a company's expectations for revenue in the market. Applying these principles to the ERCOT electricity market is relatively straight-forward, because the marginal cost of electricity is based on the price of *natural gas* more than 90% of the time.[2]

Impact of Natural Gas Prices on the Value of Texas Genco

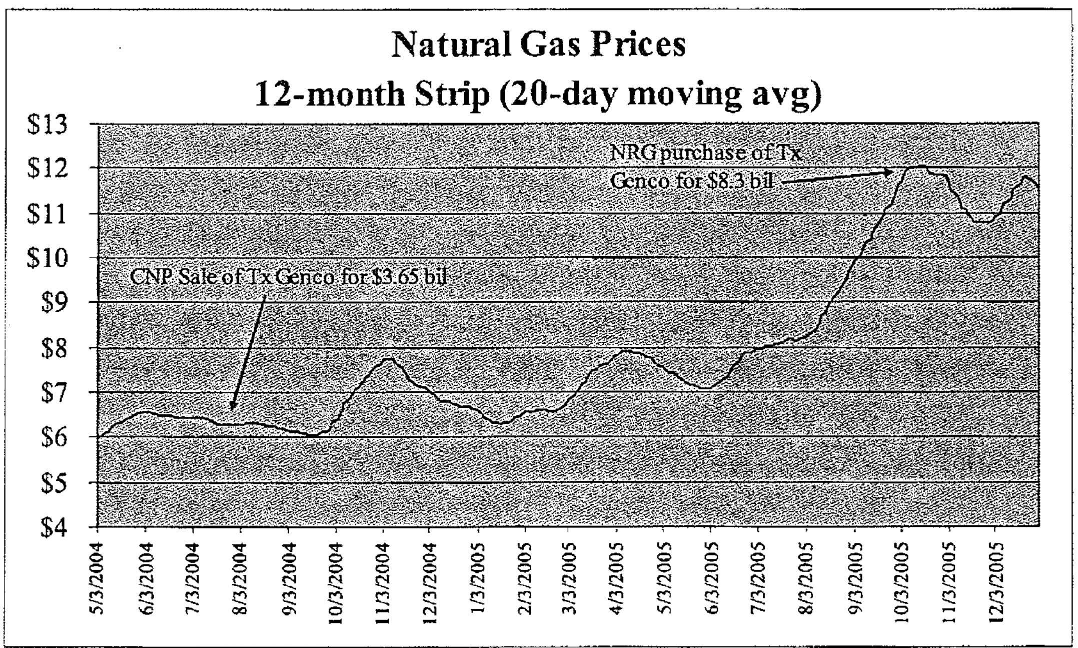
In July 2004, CenterPoint Energy announced the sale of the Texas Genco assets to *Texas Genco LLC* (an entity owned in equal parts by affiliates of The Blackstone Group, Hellman & Friedman LLC, Kohlberg Kravis Roberts & Co. L.P., and Texas Pacific Group) for a total price of approximately $3.65 billion, based on an average stock price of approximately $45.58 per share.[3] This price was based upon then-prevailing expectations of power prices and the revenues that were expected to result from those prices. The purchasers determined that $3.65 billion was the present value of Texas Genco's future margins from the sale of electricity, which were largely predicated upon the forward prices of natural gas and its role in establishing future electricity prices in ERCOT.

In connection with the CenterPoint true-up proceeding before the PUC, J.P. Morgan performed an analysis that used the valuation principles discussed above. The purpose of this analysis was to determine whether a control-premium value accrued to CenterPoint as the majority owner of Texas Genco and, if so, the amount of the premium.[4] The PUC

[2] Attached is an analysis of the sale of Texas Genco to NRG by Prudential Equity Group LLC, which addresses a number of the valuation issues covered in this report.
[3] A price of $45.25 per share was paid for CenterPoint's 80.96% ownership, while a price of $47 per share was paid for the 19.04% of shares that were publicly traded.
[4] CenterPoint prepared its true-up filing using the "partial stock valuation" method described in PURA § 39.262 to value its generation assets. For this valuation method, PURA permits the PUC to select an

selected J.P. Morgan to perform this evaluation and, through a variety of valuation techniques, including comparable sales and discounted-cash-flow (DCF) analyses, J.P. Morgan estimated the value of Texas Genco as $42.43 per share. This value was generally consistent with the values paid by *Texas Genco LLC*, as noted above (although the valuation was made at a slightly different point in time from the sale). A critical element of J.P. Morgan's DCF analysis was the expected revenue from the sale of electricity, which was based upon the price of natural gas and the resulting impact on power prices. On page 19 of its report to the PUC, J.P. Morgan emphasized that, "the Valuation Panel also performed a discounted cash flow analysis using such Texas Genco projections as adjusted for changes in the forward natural gas price curves and the implied resultant changes in power prices as of March 31, 2004 (the valuation date)."

Subsequently, in October 2005—approximately 15 months after CenterPoint's sale of Texas Genco to *Texas Genco LLC*—Texas Genco was sold again, this time to NRG Energy. The price paid by NRG was $8.3 billion, substantially higher than the previous sale amount of $3.65 billion. This dramatic difference in value, while occurring over a relatively short period of time, correlates to the increase in the price of gas between mid-2004 and late 2005. The chart below shows the change in gas prices over the period from mid-2004 through the end of 2005:



Not all generation assets would be expected to have their value change in the same way as natural gas prices. The critical factor is whether the change in gas prices affords the

independent third party to determine whether a control premium should be added to the asset value as indicated by the stock price.

assets a competitive advantage. For the owner of assets that are primarily fueled by natural gas, an increase in natural gas costs would increase both expected revenues and expected costs. The net result might be no increase in expected profitability at all. The Texas Genco assets, however, include a significant proportion of low-cost coal and nuclear generating capacity.[5] As the price of gas has risen dramatically, prices of coal and uranium have been essentially stable. This means that for Texas Genco, current and expected revenues have risen to a greater extent than current and expected costs; accordingly, expected gross margins have risen dramatically.[6]

An example will demonstrate the benefit of increases in the price of natural gas to a company with a coal or nuclear portfolio. If the price of natural gas is $4 per MMBtu, and the market heat rate is 8,000 Btu per kWh, then the market cost of electricity would be $32 per MWh.[7] (That is, 4 * 8000/1000 = 32.) If the cost to a producer of power from a coal-fired generating plant is $20 per MWh, in the $4 gas case, the coal plant would earn a margin of $12. If, on the other hand, the price of natural gas rises to $8, then the new market price of electricity, assuming the same heat rate, would be $64 per MWh. (That is, 8 * 8000/1000 = 64.) In the $8 gas case, the margin to the producer from the energy produced by coal is $44. In this example, while the cost of gas has doubled (from $4 to $8), the margin realized by a coal plant has nearly quadrupled (from $12 to $44). Thus, the values of coal and nuclear assets are substantially magnified by the widening spreads in gross margins as the value of electricity rises.

Notwithstanding the seemingly high price of $8.3 billion paid by NRG for Texas Genco, this amount will not be reflected in any regulated rate and will not determine the value of Texas Genco's production in a competitive environment. Rather, such a high price tag is simply an indication of the current value of the assets as determined in today's marketplace. Whether or not NRG ultimately recovers sufficient revenue to realize a profit on its $8.3 billion investment is dependent upon ever-evolving market conditions and its capability in operating the plants and marketing the output. There is a fundamental difference between the risk of cost recovery in a market environment and the risk in a regulated environment: in a market environment, the risk of cost recovery is borne by the owner of the asset, whereas in a regulated environment, the risk of recovery is largely borne by customers as they pay the cost of an asset through cost-of-service regulation. Consequently, whether or not NRG ultimately receives an appropriate return for its investment is unknown, but what *is* known is that customers are not intrinsically obligated to pay for cost recovery of $8.3 billion. The circumstance in which customers *would* be obligated to pay the cost of the sale of the asset would be a decision by the State

[5] Coal, lignite, and nuclear assets represent only 38% of Texas Genco's total capacity, but these solid fuel assets represent 84% of total energy production and the vast majority of revenue from operations. *Source*: NRG Presentation to Investors, page 11 (available at http://ofchq.snl.com/cache/1500006435.pdf).

[6] Texas Genco's financial reports indicate that a significant portion of its output for the near term has been sold, so that the near-term profitability is not significantly higher, but longer-term expectations of profitability have risen.

[7] The heat rate is a measure of the fuel efficiency of the generating unit. For this example, the unit would require 8 MMBtus of natural gas to generate one MWh of electricity. The market heat rate is the level of efficiency that is implied by comparing the market prices of natural gas and electricity.

of Texas to return to rate regulation. The underlying legal principle of rate regulation is a Constitutional principle: a person may not be deprived of property for public benefit without fair compensation. If regulation were restored to the electric industry in ERCOT, NRG would be entitled to recover the cost of its assets through the regulated rates.

2. Does the sale of generation assets bestow upon the purchaser an inappropriate degree of market power and, therefore, the ability to unreasonably influence market prices?

Stated simply, because NRG did not own any plants in Texas prior to the purchase of Texas Genco, there should be no increase in market power associated with this transaction. The ownership of Texas Genco is simply changing hands, and the transfer of existing assets from one unregulated entity to another has no impact on its ability to exercise market power.

If Texas Genco had been purchased by another major holder of generation assets in Texas, then the purchaser might achieve unreasonable market power and have the ability to improperly influence prices. There are provisions in PURA that deal with market power in a number of ways. One of them is a limit on the total generating capacity that a company may own.[8] Texas Genco is below that limit, and the sale to NRG did not change the percentage of capacity represented by these assets or the percentage owned by NRG. In addition, the law provides for PUC review of certain purchases of generating capacity.[9] If the purchase of generating assets increased the purchaser's ownership of generating capacity to a level that raised a market power concern, the PUC could refuse to approve the purchase or could impose conditions on its approval to minimize the impact on the purchaser's market power. These provisions of the Texas law also illustrate that the focus of public concern in connection with the sale or purchase of assets changes when competition is introduced. In a regulated environment, the law typically requires the regulatory agency to review a sale to determine the impact on rates and services to customers. This review would include a review of the sale price. In a competitive environment, owners of assets would normally have greater latitude to buy and sell assets, and the regulatory review of a sale would focus on how the sale would affect market power.

In a similar development, on January 18, 2006, PNM Resources announced that it had agreed to buy the 305 MW Twin Oaks generating plant from Sempra Energy for $480 million. The generating plant is a lignite plant in Robertson County, Texas, and prior to the purchase PNM Resources did not own other generating facilities in ERCOT. If the sales are compared on a dollar per kilowatt of capacity, including only coal and nuclear capacity, the sales prices for the Sempra and Texas Genco assets are similar. The Genco sale was for about $1590 per kilowatt, and the Sempra sale was for about $1570 per kilowatt.

[8] PURA § 39.154(a).
[9] PURA § 39.158.

Question 3: Current Rates in Non-competitive Areas

Speaker Turner's third request was as follows: "I believe that it would also be beneficial to have an analysis and response to Carol Biedrzycki's comparison between the price of electricity offered by Affiliated Retail Electric Providers and the price offered by selected electric cooperatives and municipally-owned utilities (located on the final two pages of her presentation hand-out)."

One conclusion that Ms. Biedrzycki's hand-out appears to invite is that deregulating retail rates has resulted in higher rates for customers. The comparative rate information that she provided does not support such a conclusion. Rates differed among utilities prior to competition, for a number of reasons, and rates changed in different ways for a number of reasons. One of the important factors resulting in the differences in rates and the degree of change in rates is the fuel mix of the generating plants that are used to produce power for customers. Other factors that affect rate levels are discussed below.

The other conclusion that the hand-outs suggest is that the price increases for customers buying power under the PTB were unnecessary. The Legislature could have decided not to restructure the electric industry or adopt a different approach for doing so, and this might have resulted in different rates today, but the PTB mechanism was a reasonable way to implement the new competition policy. The PTB was intended to achieve a transition to a model of competition in which Retail Electric Providers market their services, and customers make a choice of REPs. The PTB has been successful in providing price protection to customers and fostering switches. The PTB also included a rate reduction of 6% for residential and small commercial customers when competition began, so that even customers who did not switch suppliers received immediate benefits. The estimated rates under a regulated environment that are presented in response to Question 1 support the conclusion that customers have achieved rates that were better than regulated rates, whether they switched or remained with the PTB.

The broad trend that Ms. Biedrzycki's hand-out shows is that the PTB and Provider of Last Resort rates have increased to a greater degree than the rates of most of the electric cooperatives and municipally-owned utilities in Texas or the rates of electric utilities in other parts of the country. The utilities in Texas depend on natural gas for producing electricity, and some are more dependent on it than others. Since the initial fuel rates for the PTB were established in late 2001, the price of natural gas has more than tripled. Utilities that had significant ownership of coal and nuclear generation were able to minimize the increases in their electric rates. Nevertheless, the rates for most of the utilities in Texas and electric rates in other states have risen as a consequence of higher gas prices, and some of them have risen more than others.[10] In a regulated environment, the need for regulatory approval of fuel rate increases commonly has the result that increases in rates are delayed, but *reductions* in the rates are also delayed if fuel prices fall.

[10] For example, among the Texas utilities in the hand-out, an investor-owned utility, El Paso Electric Company had the smallest increase, 2%, and a cooperative, Magic Valley Electric Cooperative, had the largest, 153%.

While the information that Ms. Biedrzycki provided at the hearing of the Regulated Industries Committee was mostly correct, the rates are not a good proxy for the rates that would have been in effect in ERCOT had the utilities remained subject to rate regulation.[11] In her table 3, she showed changes in rates for regulated utilities, electric cooperatives and municipally-owned utilities. There are a number of reasons why the rates for different utilities would change at different rates and different times:

- Different utilities had different rates when retail competition began.
- Each of these utilities has made different arrangements for its long-term supply of power. For example, a number of these utilities have significant coal or nuclear generating capacity that has served to insulate them from increases in gas prices.
- The regulated investor-owned utilities operated under special circumstances after the enactment of Senate Bill 7 that limited their ability to change base rates. All of the investor-owned utilities except El Paso Electric Company were on the path to the introduction of retail competition and were subject to a statutory rate freeze until the PUC took action to delay competition. Even when competition was delayed for Entergy Gulf States, its rate freeze remained in effect initially under PUC order and now under legislation.
- El Paso Electric Company was under a ten-year rate freeze, as a part of its bankruptcy settlement, and it agreed to an extension of the freeze at about the time the original freeze expired.
- Utilities might be affected by significant growth in their service area that would require investment in new facilities.
- Utilities might be affected by the expiration of contracts to purchase power and might need to negotiate new contracts in a market that was more or less favorable than when the original contract was entered.
- The rules for the recovery of fuel costs for investor-owned utilities permit them to defer their costs, so that the recovery of cost increases is delayed and spread over a longer period.

[11] The only item that should be corrected appears in Ms. Biedrzycki's table 1, where she shows a December PTB rate for Centrica CPL of 17.70 cents/kWh and in Table 2 an increase of 99% for this REP. It appears that she transposed digits for the rate, and that the rate should have been 17.07, an increase of 92%.

Appendix 1--Specific Assumptions for Estimating Regulated Rate

Estimate of Regulated Cost of Service for TXU

1. Operating expenses are based on amounts reported by TXU in its PURA § 39.257 Annual Report for the year 2000.[12] Operations and maintenance expenses are assumed to be TXU's 2000 total operations and maintenance expense (as reported on Schedule III-A of its 2000 Annual Report) reduced by expenses associated with Alcoa's portion of the Sandow Unit, fuel and purchased power expenses, and expenses not allowed for ratemaking purposes pursuant to PURA § 36.062.

2. Capital structure and costs are based on TXU's actual capital structure and capital costs as reported in the 2000 Annual Report, except for the cost of equity, which is based on the national average for costs of equity authorized by state commissions during the year 2000.

3. Environmental costs of $400 million are amortized into cost of service to reflect expenditures related to emissions-reduction requirements of Senate Bill 7.

4. An estimated amount of $1.2 billion is amortized into the cost of service to reflect the remand of certain Comanche Peak costs originally requested in Docket No. 9300. (In June 2000, TXU filed its remand case in Docket No. 22652 requesting recovery of these costs, but subsequently dropped its request as part of its true-up settlement.)

5. Monthly fuel efficiency reports for 2000 and 2001 were used to develop base year data. The base year data included the total generation, total sales, and average price in $/MMBtu and $/MWh.

6. Coal and lignite price adjustments for both utilities were assumed to be the percentage change in the average price of coal delivered to utilities in Texas as compiled from DOE Form 423 for the years 2001-2005. More specific information for TXU and Reliant-HL&P was not available.

7. The natural gas price for gas delivered to the TXU generation sources was assumed to be the price at the Waha Hub, adjusted by the percentage change of the weighted average cost of gas at the Waha Hub from the prior year. Natural Gas Week was the source of the weighted average annual gas cost data.

8. The cost of nuclear fuel was considered stable during the 2001-2005 periods and did not change from the base year amounts.

9. Demand that could not be met from the existing TXU generating fleet came from purchases from an independent generator. This hypothetical acquisition was based on the actual demand and energy requirements of TXU Electric Delivery customers. Required capacity includes a reserve margin equal to 12% above actual firm peak demand.

10. All-in costs and heat rate for a combustion turbine were used for purposes of determining purchased capacity and energy costs. The following costs were used:

[12] Per the terms of its true-up settlement in Docket No. 25230, TXU did not file an Annual Report for the year 2001.

construction cost: \$395/kW; annual revenue requirement: \$67.27/kW; fixed O&M cost: \$10.72/kW; variable O&M cost: \$.000316/kWh; heat rate: 10,817 Btu/kWh.

11. The Functional Revenue Requirements were allocated to the Residential Class using a Residential Allocator that was derived from data from the pre-UCOS rate cases (Docket No. 18490 for TXU).

12. The annual number of bills was calculated by multiplying FERC Form 1 information by 12.

13. A weather-normalized Annual kWh was estimated by averaging FERC Form 1 data (for TXU averaged 1998-2000, for CNP averaged 1998-2001).

14. The Retail Transmission Cost of Service was allocated to Residential Customer Class using the 4CP Allocator, consistent with the UCOS cases.

15. Cost and consumption information was used to generate a hypothetical bill, assuming 1000 kWh.

16. The combined Purchased Power data and Fuel Factor data were added to the Total Base Rate in the hypothetical bill, and the total on the bill was divided by 1000 kWh to derive a cents per kWh for the Total of the Base Rate, Fuel Factor, and Purchased Power.

17. Different rates were calculated for each year to 2005, as the Fuel and Purchased Power requirements and costs changed yearly.

Estimate of Regulated Cost of Service for CenterPoint Energy

1. Operating expenses are based on amounts reported by CenterPoint in its PURA § 39.257 Annual Report for the year 2001. Operations and maintenance expenses are assumed to be CenterPoint's 2001 total operations and maintenance expense (as reported on Schedule III-A of its 2001 Annual Report) reduced by fuel and purchased power expenses and expenses not allowed for ratemaking purposes pursuant to PURA § 36.062.

2. Capital structure and costs are based on CenterPoint's actual capital structure and capital costs as reported in the 2001 Annual Report, except for the cost of equity, which is based on the national average for costs of equity authorized by state commissions during the year 2001.

3. Environmental costs of \$382 million[13] are amortized into cost of service to reflect expenditures related to emissions-reduction requirements of Senate Bill 7.

4. Monthly fuel efficiency reports for 2000 and 2001 were used to develop base year data. The base year data included the total generation, total sales, and average price in \$/MMBtu and \$/MWh.

5. Coal and lignite price adjustments for both utilities were assumed to be the percentage change in the average price of coal delivered to utilities in Texas as

[13] Of the \$718 million of environmental expenditures approved in CenterPoint's true-up case, approximately \$336 million was reflected in the 2001 Annual Report. The estimated regulated revenue requirement assumes that the difference of \$382 million is also reflected in regulated rates.

compiled from DOE Form 423 for the years 2001-2005. More specific information for TXU and Reliant-HL&P was not available.

6. The natural gas price for gas delivered to the CenterPoint generation sources was assumed to be the Katy Hub, adjusted by the percentage change of the weighted average cost of gas at the Katy Hub from the prior year. Natural Gas Week was the source of the weighted average annual gas cost data.

7. The cost of nuclear fuel was considered stable during the 2001-2005 periods and did not change from the base year amounts.

8. Demand that could not be met from the existing CenterPoint generating fleet came from purchases from an independent generator. This hypothetical acquisition was based on the actual demand and energy requirements of CenterPoint customers. Required capacity includes a reserve margin equal to 12% above actual firm peak demand.

9. All-in costs and heat rate for a combustion turbine were used for purposes of determining purchased capacity and energy costs. The following costs were used: construction cost: \$395/kW; annual revenue requirement: \$67.27/kW; fixed O&M cost: \$10.72/kW; variable O&M cost: \$.000316/kWh; heat rate: 10,817 Btu/kWh.

10. The Total Revenue Requirement was allocated using a Total Revenue Allocator derived from the total revenue allocation in the UCOS cases.

11. The Functional Revenue Requirements were allocated to the Residential Class using a Residential Allocator that was derived from data from the pre-UCOS rate cases (Docket No. 12065 for CenterPoint).

12. The annual number of bills was calculated by multiplying FERC Form 1 information by 12.

13. A weather-normalized Annual kWh was estimated by averaging FERC Form 1 data (for TXU averaged 1998-2000, for CNP averaged 1998-2001).

14. The Retail Transmission Cost of Service was allocated to Residential Customer Class using the 4CP Allocator, consistent with the UCOS cases.

15. Cost and consumption information was used to generate a hypothetical bill, assuming 1000 kWh.

16. The combined Purchased Power data and Fuel Factor data were added to the Total Base Rate in the hypothetical bill, and the total on the bill was divided by 1000 kWh to derive a cents per kWh for the Total of the Base Rate, Fuel Factor, and Purchased Power.

17. Different rates were calculated for each year to 2005, as the Fuel and Purchased Power requirements and costs changed yearly.